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User Manual for Geocost: A Computer Model for Geothermal Cost Analysis

Volume I. Steam Cycle Version

November 1975

Prepared for the U.S. Energy
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A COMPUTER MODEL FOR GEOTHERMAL COST ANALYSIS

Volume 1. Steam Cycle Version

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by
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November 1975

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ABSTRACT

A computer model called GEOCOST has been developed at Battelle, Pacific Northwest Laboratories, to rapidly and systematically calculate the potential costs of geothermal power. GEOCOST combines both technical processes and economic factors into one systematic framework and provides the flexibility to individually or collectively evaluate their economic impacts. The version of GEOCOST in this report simulates the production of electricity using a steam power conversion cycle based upon either a dry steam or hydrothermal resource. Future extensions to the model will simulate the production of electricity using other power conversion technologies, including binary fluid cycles, combined binary fluid cycles and steam, and the total flow concept.

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USER MANUAL FOR GEOCOST:
A COMPUTER MODEL FOR GEOTHERMAL COST ANALYSIS

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H. D. Huber, C. H. Bloomster, and R. A. Walter

1. INTRODUCTION

In a research program sponsored by the United States Energy Research and Development Administration, Battelle-Northwest developed a computer model for geothermal energy cost analysis called GEOCOST. Its theoretical concepts have been discussed in earlier publications.⁽¹⁻³⁾ GEOCOST simulates the production of electricity from most types of geothermal resources: dry steam, hydrothermal, geopressed and hot dry rock formations. GEOCOST is composed of two principal parts: a reservoir model which simulates the costs associated with the exploration, development, and operation of a geothermal reservoir; and a power plant model which simulates the costs associated with the design, construction, and operation of the power plant.

This report is a user manual for the steam plant version of GEOCOST. This version simulates the production of electricity using steam derived from dry steam or low salinity hydrothermal resources. GEOCOST currently has the operational capability to simulate other geothermal resources and power plant cycles. These other capabilities will be described in a later version of the user manual after their development and validation are completed.

GEOCOST is programmed in FORTRAN IV and is operational on the Control Data Cyber 74-18 computer with Scope 3.4.2 operating system. The source code for GEOCOST and the 1967 ASME Steam Tables^(4,5) used to calculate thermodynamic and physical properties of water and steam are available from the Argonne Code Center on one reel of magnetic tape. The standard FORTRAN system library functions, such as the square root, exponential, logarithm, sine, cosine, minimum, and maximum functions, are assumed to be available at

the user's computer installation and are not included on the tape. The tape recording mode is optional: 7-track, 556 BPI, even parity, and BCD code; or 9-track, 800 BPI, odd parity, and EBCDIC code. The example problem input and output included in this report describe a bench mark case for use in verifying the conversion of the code to the user's computer installation.

2. DESCRIPTION OF PROGRAM

2.1 GENERAL PROGRAM DESIGN

GEOCOST is designed in modular fashion, with 63 technical and economic subroutines. In addition to the standard FORTRAN library functions, 63 subroutines comprising the 1967 ASME Steam Tables calculate thermodynamic and physical properties of water and steam, including pressure, temperature, enthalpy, entropy, specific volume, density, viscosity, and steam quality. GEOCOST and the steam tables contain approximately 8000 and 4000 FORTRAN statements respectively. The entire program requires approximately 46000 decimal words of computer memory without overlay or segmented loading and 36000 decimal words with segmented loading. One disk file is required for storage of summary printout when using the consecutive case generation input option described later in this manual.

The block diagram in Figure 1 shows an overview of the technoeconomic model used in GEOCOST to represent a geothermal power system. Figure 2 shows the computational flow through the major submodels of GEOCOST. Figure 3 shows the detailed, logical layout of the subroutines in each major submodel and serves as the basis for the operational description of the major sequence of calculations in GEOCOST. The user may find referring to Figure 3 helpful in reading the following description of the major submodels and their associated subroutines. The steam table functions are called from many subroutines in GEOCOST, but are not shown in Figure 3 for the sake of brevity. These functions are summarized following the description of the subroutines in GEOCOST.

2.2 EXECUTIVE PROGRAM AND DATA INPUT SUBMODEL

The executive program GEOCOST controls the sequence of processing by the major submodels to simulate the technical and economic components of the geothermal model. This includes the data input; steam power plant system; fluid transmission and disposal; cash flow for the reservoir exploration, development, and operation; and cash flow for the power plant design,

FIGURE 1. Technoeconomic Model for a Geothermal Power System

FIGURE 2. Computational Flow Through the Major Submodels of GEOCOST

GEOCOST MODEL

DETAIL OF SUBMODELS IDENTIFIED BY NUMBER

(THE SECOND NAME FOLLOWING A/MARK FOR SOME SUBROUTINES INDICATES AN ALTERNATE ENTRY POINT IN THE SUBROUTINE)

FIGURE 3. Detailed Flow Diagram for GEOCOST

construction, and operation. GEOCOST calls the data input submodel simulated by subroutine LOAD and its associated subroutines to set up the initialization and read the technical and economic input data. This includes the reservoir characteristics, wellhead conditions of the geothermal fluid, well field layout, fluid transmission and disposal parameters, drilling costs, power plant design and capacity, and financial and tax data for the reservoir and power plant. Each subroutine associated with the executive program and with the data input submodel is described in the order of its execution in the program (refer to Figure 3, page 6).

GEOCOST Controls the sequence of calculations by the major submodels.

BLOCK DATA Initializes representative values for the input data when the program is loaded into computer memory.

CCSR1, CCSR2, Initialize steam constants required in calculations by the
CCSR3, CCBLL, steam table functions.
and COMALL

LOAD Reads the input data using NAMELIST to override the default values initialized in BLOCK DATA; sets up initial values for the GEOCOST variables; and prints the input data defining reservoir characteristics, well properties, and fluid composition. Subroutine LOAD also calls subroutine DSTEAM to execute the steam power plant and fluid transmission and disposal submodels.

SWITCH(0) Stores the first 35 values of the DINPUT array defining input reservoir financial and tax data into an internal work array, D(N), $N = 1, \dots, 35$. SWITCH(1) stores the second set of 35 values of the DINPUT array, DINPUT(N), $N = 36, \dots, 70$, defining input power plant financial and tax data into the same work array, D(N), $N = 1, \dots, 35$. The common work array has similar definitions for the reservoir and power plant, although the individual elements transferred from the first and second set of 35 values in the DINPUT array can have different numerical values.

DEGC Returns Centigrade temperature expressed as a positive number when Fahrenheit temperature is input as a negative number. Centigrade temperature input as a positive number is returned unchanged. The input parameter which can use this option is the wellhead temperature PWTEMP.

FEET Returns meters expressed as a positive number when feet are input as a negative number. Meters input as a positive number are returned unchanged. The input parameter which can use this option is the well depth STRATA(2,1).

INCHES Returns centimeters expressed as a positive number when inches are input as a negative number. Centimeters input as a positive number are returned unchanged. The input parameter which can use this option is the well diameter DIA.

PAGE Controls the number of lines printed per page, prints an input title at the top of the page, and numbers pages when called from various subroutines.

GEVAL Adjusts the input array EVALUE during case generation runs if an abnormal termination occurs during the iteration between the steam power plant and fluid transmission submodels. The EVALUE array consists of two design parameters for changing internal pipe diameters in the fluid transmission submodel to alter pressure degradation. The input parameter EVALUE(1) is adjusted to change the diameters of all fluid transmission pipes conducting water; EVALUE(2) is adjusted for pipes conducting steam or two-phase mixtures of steam and water. The adjusted EVALUE array is used to restart a case that aborted due to unacceptable fluid quality in the fluid transmission pipes. This may be due to two-phase flow, which the user has optionally specified as undesirable by setting the input parameter LTPHAS = 0, or

GEVAL
(contd)

it may result from a pressure drop to a point below the turbine exhaust pressure, defined by the input parameter PCOND.

SCASE

Summarizes case generation runs by printing the parametric combinations defining the case; final values of the EVALUE array when subroutine GEVAL adjusts this array; and reservoir cost, power plant cost, and total cost of geothermal power.

GCASE

Generates consecutive cases when the case generation option is employed to facilitate parametric studies as combinations of the parameters: wellhead temperature ($^{\circ}\text{C}$), wellhead flow rate (lb/hr), power plant size (MWe), well spacing (acres), and well life (years).

2.3 CONTROL ROUTINE FOR STEAM POWER PLANT AND FLUID TRANSMISSION SUBMODELS

Subroutine LOAD calls subroutine DSTEAM to control the interaction between the steam power plant submodel and the fluid transmission submodel. Subroutine DSTEAM calls the FLASH subroutine to set the wellhead pressure of the geothermal fluid at saturation or above and to simulate flashing of high-temperature water to steam. Subroutine DSTEAM also sets the pressure of the water exiting from wellhead steam separators at saturation or above whenever this water is transmitted for flashing at the plant. Overpressurization above saturation is used to prevent two-phase flow in the fluid transmission pipes when water is conducted to the plant. The overpressurization required to prevent two-phase flow is minimized by making two passes through the fluid transmission submodel during the first iteration between the steam power plant and fluid transmission submodels.* Two-phase flow is allowed in the transmission of steam to the plant by setting

* See description of steam separation and flashing configuration five in Appendix B.

the input variable LTPHAS to 1 and prohibited by setting LTPHAS to 0. Subroutine DSTEAM together with the fluid transmission submodel simulates the removal of all steam condensate that forms from two-phase flow in the transmission of steam to the plant.

Subroutine DSTEAM initiates and controls the iteration between the steam power plant submodel and the fluid transmission submodel. Subroutine DSTEAM calls subroutine STEAM and its associated subroutines to initially calculate the power plant's total fluid flow requirements from the reservoir using wellhead conditions. Based upon the total flow requirements, the fluid transmission submodel simulated by subroutine TRANS and its associated subroutines is called to calculate the number of wells required, pipe lengths and diameters, pumping requirements, and the temperature and pressure drop (fluid degradation) between the reservoir and power plant. Subroutine DSTEAM controls the iteration between the steam power plant submodel, which calculates the increased total fluid flow rate required for the power plant under the degraded fluid conditions, and the fluid transmission submodel, which provides the increased flow requirements by adding wells and determining the new temperature and pressure drop.

Subroutine DSTEAM calls subroutine CONVRG to test the iteration between the steam power plant submodel and fluid transmission submodel for convergence of geothermal flow rate. This process may continue up to a maximum of 10 iterations or until the flow demanded for the power plant converges, which is currently defined as a change in the flow requirement for the power plant of less than 2% from the flow requirement computed in the previous iteration. As an option, subroutine DSTEAM calls subroutine SCRUBR simulating a water scrubber to remove impurities from the steam. After convergence, subroutine DSTEAM calls the fluid disposal submodel, beginning with the entry point INJECT in subroutine TRANS to calculate the number of injection wells, injection pipe diameters, and lengths.

The subroutines associated with subroutine DSTEAM are described below. The subroutines associated with the steam power plant submodel and fluid transmission submodel are described separately in the next two sections because of their size and importance.

FLASH Simulates the flashing of high-temperature water or two-phase mixtures of water and steam in the field or at the plant to steam. Subroutine FLASH is capable of handling up to four successive stages of flashing. The saturated steam temperature, pressure, enthalpy, and mass fraction of each flash stage are calculated as a function of the inlet fluid temperature, pressure, inlet steam fraction, number of flash stages desired, and options indicating whether steam present in the inlet fluid is to be separated or mixed with the flashed steam. Flash temperatures are based on maximizing the thermal energy available for power generation. Field and plant flashing are simulated by setting the number of flash stages (NFLASH) greater than 0 and the location of the flashers (LFLASH) to 0 or 1 respectively.

SCRUBR Simulates a water scrubber which removes the majority of particulates in the steam prior to turbine inlet without substantially degrading the steam quality and pressure. This component is optional and is simulated by setting the input variable ISCRUB to 1.

FLUID Correlates physical and thermodynamic properties of water and steam to polynomial functions of temperature up to the third degree, based on data from various sources.⁽⁵⁻⁷⁾ The polynomials are used to predict the following properties as a function of temperature at saturation: specific heat, thermal conductivity, density, viscosity, heat of vaporization, and surface tension. Critical pressure, critical temperature, and molecular weight are included as constants. A warning message is printed if the input temperature requires extrapolating the polynomials beyond the temperature range used in generating the empirical equations.

CONVRG Tests the iteration between the steam power plant and fluid transmission submodels for convergence of geothermal flow rate. Subroutine CONVRG compares the total flow requirements computed by the steam power plant submodel, based upon the degraded temperature and pressure of the geothermal fluid delivered by the fluid transmission submodel in the current iteration, with the total flow requirement calculated in the previous iteration. After convergence, the steam power plant and fluid transmission submodels are executed one more time at the control of subroutine DSTEAM. This provides flexibility to satisfy the input options of printing the final iteration only or printing the entire iteration history. Failure to converge within the maximum limit of 10 iterations results in an abnormal termination and printout of an appropriate error message.

2.4 STEAM POWER PLANT SUBMODEL

Subroutine DSTEAM calls the steam power plant submodel simulated by subroutine STEAM and its associated subroutines to calculate the power plant's total fluid flow requirements and internal power consumption. The initial calculations are based upon wellhead conditions. Subsequent calculations in the iteration between the steam power plant and fluid transmission submodels are based upon the degraded fluid conditions transmitted by the fluid transmission submodel. Subroutine STEAM calls the subroutines described below to simulate the operating characteristics of the major components of the steam power plant submodel shown in Figure 4: steam turbine, electrical generator, condenser, gas ejector, and cooling tower.

GSEJCT Simulates the extraction of the noncondensable gases (principally CO_2) in the exhaust steam from the steam condenser using a two-stage steam jet ejector with inter- and after-condensers.

TURBO Simulates the operating characteristics of a steam expansion turbine coupled to a three-phase, hydrogen-cooled, AC-synchronous generator. The turbine is designed to exhaust optionally at or below atmospheric pressure and allows multiple inlet streams

FIGURE 4. Flash Steam Plant

- TURBO
(Contd) of steam flow, which are introduced into different stages of the same turbine. The mass flow rate of geothermal fluid (lb/hr) required from the reservoir to operate the turbine is calculated based upon the preassigned gross kilowatt output of the power plant, the inlet steam pressure, enthalpy, and the weight fraction of non-condensable gases in the steam. The auxiliary steam flow rate required by the gas ejector and individual steam flows in each inlet stream to the turbine are also calculated. An internal efficiency of 75% is assumed for the turbine.
- SCNDSR Calculates the cooling water flow rates required to condense the exhaust steam from the turbine in a barometric, direct contact condenser. The required cooling water flow rates are also calculated for the inter- and after-condensers in the two-stage gas ejector.
- QCC Calculates the cooling water flow rates required by the turbine oil cooler and the generator hydrogen cooler.
- TOWER Calculates the cooling tower air flow rate and evaporation rate based upon an induced-draft evaporative cooling tower in which air is drawn through the tower with large axial flow fans.
- SLOSS Calculates the internal power (kilowatts) consumed by the cooling tower fans, condensate pumps, cooling water pumps, scrubber pump, pumps for reinjecting geothermal fluid remaining after flashing, and booster pumps for overpressurizing geothermal fluid. The losses are subtracted from the gross kilowatt output designed for the power plant yielding the net kilowatt output.

2.5 FLUID TRANSMISSION AND DISPOSAL SUBMODEL

Based upon the total flow requirements calculated by the steam power plant submodel, subroutine TRANS calls the subroutines described below to simulate the fluid transmission submodel. The fluid transmission submodel calculates the following quantities: number of producing wells required, the well field layout, pipeline lengths, optimum pipeline diameters, pipe

schedules, pipe insulation, pumping requirements, fluid degradation during conduction from the wellhead to the power plant, and cost of the pipes, insulation, pumps, wellhead separators, wellhead flashers, valves, and associated equipment. The degradation of the geothermal fluid (temperature, pressure, enthalpy, steam quality, viscosity, and density) is modeled on a node-by-node basis during conduction of any of the five following fluid conditions: compressed liquid, saturated liquid, two-phase mixture, saturated vapor, and superheated steam.

Subroutine INJECT, coded as an entry point in subroutine TRANS, performs analogous functions for fluid disposal by simulating the conduction of the effluent water from the wellheads and power plant to the injection well field. It calculates the number of injection wells required, injection well field layout, effluent pipeline lengths and diameters, and cost of the disposal piping system and associated equipment. In contrast to the fluid transmission submodel, which calculates fluid degradation on a node-by-node basis, the more simplified fluid disposal submodel in this version of GEOCOST does not calculate effluent fluid degradation. Instead, the effluent pipeline diameters are sized on a node-by-node basis as a function of the mass flow rate exiting each node, holding constant the temperature, pressure, viscosity, and density of the effluent in effect at the outlet from the field- or plant-located flashers and power plant cooling tower.

TROUT	Prints the input conditions for the fluid transmission and disposal submodel.
DESIGN	Calculates the number of producing, nonproducing, and injection wells based on the total geothermal fluid flow rate demanded by the steam power plant submodel and several input conditions. The latter includes: mass flow rate of individual producing wells, ratio of nonproducing to producing wells drilled, and ratio of injection well to producing well flow rate. The wells are located at the vertices of equilateral triangles (nodes in a triangular lattice) as shown in Figure 5, with pipe runs parallel to the

FIGURE 5. Well Layout Design and Routing of Fluid Transmission Lines

DESIGN (Contd) horizontal X-axis. Separate, parallel transmission lines conduct separated steam, flashed steam, and water from the wells to the power plant. Each different transmission system has a separate manifold pipeline for transmitting the geothermal fluid from all rows of wells to the power plant. Subroutine DESIGN calculates an effective average acreage (WACRE) per producing well based upon the input well spacing (WELSPC) in acres and the fraction (FRCNPW) of nonproducing (dry) wells according to the following equation:

$$WACRE = WELSPC * (1 + FRCNPW)$$

The area (WACRE) encompassed by each producing well (Figure 5) is equal to the area of two equilateral triangles. Subroutine

DESIGN calculates the pipe length between producing wells based on the equation for the area of an equilateral triangle as follows:

$$\text{Pipe length (m)} = (0.3048006) (5280) \sqrt{\frac{\text{WACRE (acres)}}{(0.86603) (640)}}$$

EQCOST

Calculates the cost of valves, instrumentation, rock separators, cyclone separator, and steam separators for the fluid transmission submodel. Subroutine EQCOST calls subroutine CFLASH to calculate the cost of field-located flashers.

CFLASH

Calculates the cost of field- or plant-located flashers based on the number of flash stages, inlet water pressure to each stage, and the exit steam flow rate from each stage. Field-located flashers are costed at each producing well and multiplied by the number of producing wells. Plant-located flashers are costed as one multistage unit at the plant by using the inlet water pressure and exit steam flow rate collectively from all producing wells. The equipment cost is multiplied by a factor of two for both field- and plant-located flashers to account for installation costs.

TSTART

Initializes the thermodynamic and physical conditions of the geothermal fluid at the two types of nodes in the triangular lattice defining the well-field layout. These types are 1) well nodes and 2) pipe junctions or manifold nodes collecting the fluid from the parallel rows of pipes into one large pipe leading to the power plant. The following fluid conditions are initialized on a node-by-node basis: temperature, pressure and flow rate (input variables); enthalpy (computed as a function of the input temperature, pressure, and steam quality); and density and viscosity (computed from the preceding conditions). All well nodes in the field are initialized with the same average properties. Variable well

TSTART (contd) properties can be simulated with minor code modifications. The initial conditions at the nodes are used as the starting point for computing the fluid degradation on a node-by-node basis during conduction from the well field nodes to the power plant.

PIPE Calculates the optimum pipe diameter exiting each node. The calculation is based on the fluid mass flow rate, fluid density and viscosity, and economic trade-offs between the components comprising the cost function of the fluid transmission system: capital cost of the pipe, annual value of energy lost due to friction in the pipeline, and capital cost of pumps and drive motors. Steam or two-phase mixtures of steam and water entering the transmission pipes from the wellheads are conducted to the power plant without pumping. Thus, the cost function for conducting steam or two-phase mixtures of steam and water does not include capital costs for pumps and drive motors.

On the other hand, water entering the transmission pipes from the wellheads is pumped to the power plant by setting the overpressurization factor PRFACT >1 in the input data. The cost function for conducting water includes capital costs for pumps and drive motors. The transmission cost function, comprised of two and three terms for steam and water pipes respectively, is differentiated with respect to internal pipe diameter. An explicit solution is derived for optimum steam pipe diameters. An iterative solution based upon the Newton-Raphson algorithm is obtained for the more complicated cost function for optimum water pipe diameters. The pipe equations include a parameter EVALUE which can be adjusted by the program user in the input data to change all pipe diameters in the pipeline network. The parameter EVALUE(1) is adjusted for pipes conducting water and EVALUE(2) is adjusted for pipes conducting steam

PIPE (contd) or two-phase mixtures of steam and water. This option permits the user to avoid unacceptable fluid quality resulting from excessive pressure degradation or from two-phase flow of steam and water mixtures in the pipeline.

STORE/RETRIEV Saves and retrieves information associated with the pipeline and thermodynamic condition of the fluid computed in simulating fluid conduction and degradation from well nodes (nonmanifold nodes) to adjacent nodes. Calculations are required only once for each set of well nodes in the well layout with the same number of active wells upstream of the nodes, providing all wells have the same average properties.* The subsequent retrieval of this information in lieu of recomputation can reduce the execution time for simulating the fluid transmission submodel almost 50% for large well fields. This option is selected by setting the input parameter IAVWEL = 1.

SCHEDL Assigns pipe schedules on a node-by-node basis by selecting the smallest pipe schedule from a range of 10 to 160 that can withstand the maximum fluid pressure exiting each node. The maximum pressure each schedule can accommodate is a function of the fluid temperature and ranges from about 350 psia for schedule 10 up to 3000 psia for schedule 160, with temperature ranges from 100 to 900°F. The pipe schedule and diameter are used in subroutine TRANS to calculate the cost of piping and installation.

INSUL Sizes pipe insulation on a node-by-node basis as a function of the fluid temperature, nominal outer pipe diameter, insulation thickness availability, and cost, using one or more types of insulation. The cost of insulation is calculated based on the thickness of each type of insulation used.

* See description of sample case output.

SPFLOW

Calculates the pressure, enthalpy, and temperature drop of the geothermal fluid during single-phase flow in the pipeline between nodes, using 50-ft consecutive stepwise increments down the pipe. The enthalpy drop is calculated as a function of nominal outer pipe diameter, fluid temperature, and insulation thickness. The pressure drop is calculated as a function of the mass flow rate, viscosity, density, and internal pipe diameter. The temperature drop is obtained from the pressure and enthalpy drop by using the appropriate steam table function for the single-phase fluid condition in effect at the beginning of the 50-ft step increment: compressed liquid, saturated liquid, saturated vapor, or superheated steam.

TPFLOW

Calculates the pressure drop of the geothermal fluid due to friction and acceleration during horizontal two-phase flow in the pipeline between nodes, using 50-ft consecutive stepwise increments down the pipe. The calculation is based upon a modified model proposed by A. E. Dukler⁽⁸⁾ to determine the frictional pressure drop for horizontal two-phase flow. The model assumes constant slippage between the two phases of flow and uses G. A. Hughmark's⁽⁹⁾ liquid holdup correlation factor to estimate the in-place volumetric holdup. On account of the slippage and the variation in density from one phase to the other, a significant pressure drop can also develop due to the acceleration of the gaseous phase. By applying a mechanical energy balance to the flow, A. E. DeGance and R. W. Atherton⁽¹⁰⁾ were able to modify Dukler's model to take into account the accelerational pressure drop. In addition, J. H. Vohr⁽¹¹⁾ applied a mechanical energy balance to the flow to obtain a general relation for the total pressure drop, which includes both frictional and accelerational pressure drop components.

TPFLOW (contd) The model used in subroutine TPFLOW assumes a smooth-tube friction factor for pipe roughness. The single-phase enthalpy loss equation, as used in subroutine SPFLOW, also approximates the heat loss through the pipe wall and insulation during two-phase flow. The temperature drop is obtained from the TPH function in the steam tables based on the pressure and enthalpy drop.

FLPROP Identifies the fluid condition in the transmission pipeline as compressed liquid, saturated liquid, two-phase mixture, saturated vapor, or superheated steam. Subroutine TRANS calls FLPROP on a node-by-node basis. The fluid condition is identified based upon the pressure and enthalpy by interrogating subroutine XPHH and the ASME Steam Table functions. After identification of the fluid condition at a particular node, subroutine FLPROP calls the appropriate steam table function to compute the specific volume, density, viscosity, temperature, or entropy as requested by subroutine TRANS.

XPHH Calculates the steam quality by weight fraction as a function of pressure and enthalpy. It returns 0 for saturated and compressed liquid, 1 for saturated vapor and superheated steam, and values in between for two-phase mixtures of steam and water at saturation.

TPHASE Tests whether the fluid quality in the pipeline has become unacceptable due to either pressure degradation below the minimum exhaust pressure permitted for the turbine or two-phase flow. Subroutine TPHASE tests for two-phase flow if the input parameter LTPHAS = 0, which allows single-phase flow only. If the test detects two-phase flow, an appropriate message is printed and control is returned to the executive program GEOCOST for reading the next set of input data, unless the case generation option is employed. In the case generation mode, subroutine GEVAL adjusts the

TPHASE (contd) EVALUATE array, which in turn affects the pipe diameters and pressure degradation in the fluid transmission pipeline, to try to maintain single-phase flow for the entire length of the pipeline to the power plant. The test for two-phase flow is bypassed if the input parameter LTPHAS = 1, allowing two-phase flow.

TPRINT Prints the results calculated by the fluid transmission submodel for each transmission line from the well field to the power plant. Results can be printed for the entire steam power plant and fluid transmission iteration history, or only for the final iteration satisfying the convergence criterion. In the final iteration, results calculated by the fluid disposal submodel are also printed. The input parameter LL6 controls the printout for the steam power plant and fluid transmission iteration: LL6 = 0 suppresses all printout, LL6 = 1 prints the last iteration only, and LL6 = 2 prints the full iteration history.

MOUT Prints the arrays calculated in the fluid transmission and disposal submodel as matrices or vectors with accompanying titles.

2.6 RESERVOIR ECONOMIC SUBMODEL

After the required total fluid flow is established, GEOCOST calls the reservoir economic submodel simulated by subroutine RESVOR and its associated subroutines. This submodel determines the cash flow associated with the exploration, development, and operation of the reservoir from the beginning of exploration through the economic life of the power plant. The exploration process identifies and evaluates potential reservoir sites by a series of discrete steps, which can occur either sequentially in time or with some specified time overlap. Each step has a task description, time period, associated cost, and success ratio (finding rate). The major steps are: 1) identification of target sites, 2) preliminary reconnaissance, 3) detailed reconnaissance, 4) identification of drillable sites,

5) exploratory drilling, 6) development of the reservoir and fluid transmission and disposal system, and 7) operation of that system. Both capitalized and expensed costs are determined for each of the steps in the reservoir exploration. Only that fraction of the total exploration cost calculated for the specified reservoir producing capacity required to provide the energy supply for the specified power plant size is included in the cost of energy to the power plant.

Reservoir development and operation expenses are based upon the number of producing, nonproducing, and injection wells and the fluid transmission and disposal system established in the steam power plant and fluid transmission iteration. Reservoir development costs include: drilling costs based upon the required number of wells and the drilling costs input for individual producing, nonproducing, and injection wells; capital cost of the fluid transmission system calculated in subroutine TRANS; and capital cost of the fluid disposal system calculated in subroutine INJECT. The cost of drilling producing wells is subdivided into both tangible and intangible drilling costs because tax regulations may treat these costs differently. Costed reservoir operation tasks include: replacement well drilling, subdivided into tangible and intangible costs; nonproducing well drilling associated with replacement wells; well abandonment and maintenance; overhead and management; well redrilling due to scale buildup; and fluid transmission and disposal maintenance. Both reservoir development and operation costs are computed on the basis of the specified power plant size.

Using discounted cash flow analysis, the unit cost of energy from the reservoir is calculated by equating the present worth of the revenues and expenses from the beginning of reservoir exploration through the economic life of the power plant. Descriptions follow of the subroutines associated with subroutine RESVOR and the reservoir economic submodel.

CLEAR Clears consecutive locations in memory for initializing arrays in various subroutines to zero.

TARGTS Calculates the number of prospective geothermal sites to explore in each of the successive discrete steps comprising the reservoir

TARGTS (contd) exploration process, based upon the success ratios (finding rates) input for each step. The successive reduction in the number of sites to explore at each step culminates in a single producible site at the last step, completing the exploration process.

DATAACK Prints the financial and tax input data for the reservoir and both calculates and prints the reservoir's annual cash flow statement from exploration through the economic life of the power plant. This statement includes each year of exploration, development, and operation of the reservoir, the power plant load factor or fraction of annual time the power plant is operating at full capacity, and the cash flows computed on an annual basis for the following items: identifying geothermal target sites, remaining reservoir exploration beginning with preliminary reconnaissance, reservoir development, reservoir operation, property taxes and insurance, interim capital replacements for the fluid transmission and disposal system, and the sum of these costs.

FACTRS Calculates the present worth discount factor based on the cost of capital from both debt (bond) and equity (stock) financing, using the effective bond interest rate after taxes. All expenses and revenues are assumed to be incurred at midyear. If year-end discounting is desired, the variable TIMD appearing in subroutine FACTRS should be reset from 0.5 to 1.0 in the BLOCK DATA subroutine. Subroutine FACTRS is called by both the reservoir and power plant subroutines as shown in Figure 3.

PWRCO Calculates the annual reservoir operating expenses from exploration through the economic life of the power plant. Subroutine PWRCO also calls subroutine DEPREC to calculate well depreciation and reservoir depletion and depreciation. These are printed by subroutine OUTPUT in the statement of annual deductible expenses.

DEPREC Calculates the annual depreciation of the reservoir capital assets, including interim capital replacements. The input parameter LL2

DEPREC (contd) selects one of two available options: the straight line method (LL2 = 1) or the sum-of-years-digits method (LL2 = 2).

COSTEQ Calculates the unit cost of energy from the reservoir by setting the present worth of the revenues equal to the present worth of the expenses from the beginning of reservoir exploration through the economic life of the power plant.

Unit cost of energy (mills/kW-hr) = (present worth of the expenses - present worth of tax credits) / [(present worth of energy supplied) * (1 - state gross revenue tax rate) * (1 - combined federal and state income tax rate)].

PAYOUT Calculates the annual income statement and annual payout of investments for the reservoir. This includes the total energy sales (gross revenues), state and federal income taxes, revenue taxes, royalty payments, and the changes in capitalization: outstanding bonds, bonds repaid, unrecovered equity, equity recovered, bond interest, and earnings on unrecovered equity.

OUTPUT Prints the statements of annual deductible expenses, income, and payout of investments for the reservoir from the beginning of reservoir exploration through the economic life of the power plant. The statement of annual deductible expenses lists the items: year, present worth factor for that year, reservoir operating expenses, bond interest, well depreciation, reservoir depletion and depreciation, total deductible operating expenses, and state income taxes. The statement of annual income lists the items: year, million megawatt-hours of energy supplied, energy sales, byproduct sales (zero for this version of GEOCOST), revenue taxes, royalty payments, total tax deductible expenses, taxable income (federal), and federal income tax. The statement of payout of investments lists the items: year, net cash flow, outstanding bonds, equity capital not recovered, bond interest, earnings on unrecovered equity, bonds repaid, and recovery of equity.

SUMMARY Calculates and prints the breakdown of the unit cost of energy from the reservoir in mills/kW-hr and equivalent annual costs in millions of dollars. These are itemized as follows: identification and exploration, development, operating costs, revenue taxes, state income taxes, royalty payments, federal income taxes, bond interest, and byproduct revenue (zero for this version of GEOCOST). In another set of calculations, the taxes, royalty payments, and bond interest are reallocated to the direct cost components for the reservoir: identification and exploration, development, and operating costs. The rate of return on investment is included in the distributed energy cost for each component. The deductible nature of the bond interest causes this expense to be partially included in the rate of return (the part which is included in the present worth factor) and the remainder to be accounted for separately.

WRITE Prints debugging information from the reservoir economic submodel when the variable LL4 is nonzero. The variable LL4 is currently set to 0 in the BLOCK DATA subroutine.

2.7 POWER PLANT ECONOMIC SUBMODEL

The reservoir revenue is a cost to the power plant. GEOCOST calls the power plant economic submodel, simulated by subroutine PWRPLT and its associated subroutines. This submodel combines the reservoir cost with the other power plant capital and operating costs and generates the cash flow associated with the design, construction, and operation of the power plant throughout its useful life. The required revenue and unit cost of electricity are determined by using discounted cash flow analysis, and equating the present worth of the revenues and expenses over the economic life of the power plant. Descriptions of the subroutines associated with subroutine PWRPLT and the power plant economic submodel follow.

PCONST Generates capital cost estimates for the design and construction of the power plant, heat rejection system, and electrical switchyard as a function of power level or process flow rates. Equipment cost data was obtained from industry vendors and utility

PCONST
(contd)

operators for geothermal power plants. The cost data was correlated by least squares to the following equation, which is used to predict costs for various power levels and geothermal conditions.

$$\text{Installed cost (thousands of dollars)} = a + b(x)^s$$

where:

a reflects fixed costs.

b reflects materials, equipment, and installation dependent costs.

s is a size scale factor.

x is the independent variable such as plant power or some process flow rate.

The cost categories use a decimal indexing account system.

Table 1 presents the coefficients of the equations for costing the various components of the power plant. All costs are in December 1974 dollars.

VAL Called from subroutine PCONST, rounds the estimated capital costs of the power plant to the nearest thousands of dollars in order to avoid any misinterpretation that the costs can be predicted to figures of greater accuracy.

DATAK Prints the financial and tax input data for the power plant.

EXPENSE Calculates the power plant capital investment expenditure as a function of time over the number of years input for plant construction. The calculation is based on the following function:

$$C(t) = \frac{100}{1 + e^{k(a-t)}}$$

where:

C(t) is the cumulative percent expenditure at time t.

k is a constant, 0.0847.

a is the 50% expenditure point in time, currently set to the 60% point in the construction schedule.

t is the time in years.

TABLE 1. Steam Power Plant Capital Cost Coefficients

Account No.	Component	a	b	s	Comments
1.0	Power Plant	650	190	1	(1), (a)
1.1	Piping, Insulation, Pumps & Tanks	2	3.9E-4	1	(2)
1.2	Crane	160	0.53	1	(1)
1.3	Turbo Generator (Sun)	{ 36 0	5.0 0.37	1 0.68	(1) (2)
1.6	Flashers (Plant Located Units)				(3)
1.9	Misc. Support Equipment	0	4.4	0.85	(1)
1.10	Instrumentation and Controllers	0	6.0E-4	1	(2)
1.12	Electrical Support Equipment	4	18	0.92	(1)
1.16	Condenser	370	6.1E-4	1	(2)
1.17	Installation Testing	5	3	1	(1)
1.18	Buildings, Structures, & Foundations	250	24	1	(1)
1.19	Gas Ejectors (Steam Driven)	78	1.62	0.6	(4)
1.20	Flash Water Reinjection Pump (Plant Located Flasher Unit)				(5)
1.21	Cooling Tower Reinjection Pump				(6)
1.99	Total 1.0				
2.0	Heat Rejection System				
2.1	Wet Cooling Tower System	690	6.1E-4	1	(2)
2.99	Total 2.0				
3.0	Switch Yard	6	96	0.52	(1)
3.99	Total 3.0				
5.0	Other Costs		4.99		
5.1	Engineering and Design	$C_{ED} = 0.1$	$\sum$ cost $\Lambda = 1.99$		
5.2	Administration and Indirect Costs			$0.8 C_{ED}$	
5.99	Total 5.0				

(1) Use x = plant power (MWe)

(2) Use x - total steam flow rate (lb/hr) 0.9996 *

(3) Cost of flasher (\$) = $\sum (2.) (0.22141) (\text{exit steam flow rate})$
(water inlet pressure)^N 0.09795

where the factor of 2 reflects the cost of installation and N = number of flash stages.

(4) Use x = gas ejection rate (cfm)

(5) Cost of pump (\$) = $2.43 [(\text{flash reject water flow rate}) * (\text{pressure increase of 50 psi})]$ 0.568

(6) Cost of pump (\$) = $2.43 [(\text{excess cooling water flow rate}) * (\text{pressure increase of 50 psi})]$ 0.568

(a) Estimate based on worldwide geothermal flash or dry steam plant costs.

Subroutine EXPENSE calculates the following costs appearing in the annual cash flow statement for the power plant: capital investment expenditure, plant operating costs, interim capital replacement, property taxes and insurance, and the sum of these costs with the energy cost from the reservoir. Annual plant operating cost is calculated as a function of plant size based on utility statistics.

$$\text{Operating cost (\$)} = 1455 * (\text{plant size in MWe})^{0.9}$$

Added to this cost is an annual maintenance cost, calculated as a function of plant capital cost.

$$\text{Maintenance cost (\$)} = 0.004 * (\text{plant capital cost})$$

Interim capital replacements are also calculated as a function of plant capital costs.

$$\text{Interim capital replacement (\$)} = [\text{input constant DINPUT(53), with default value 0.0035}] * (\text{plant capital cost})$$

Property taxes and insurance are calculated as a function of plant capital cost as well.

$$\text{Property tax (\$)} = [\text{input constant DINPUT(52), with default value 0.0250}] * (\text{plant capital cost})$$

$$\text{Property insurance (\$)} = [\text{input constant DINPUT(54), with default value 0.0012}] * (\text{plant capital cost})$$

Subroutine EXPENSE also calculates the power plant's annual net production of electricity in units of kilowatt-hours and millions of megawatt-hours, taking into account the power plant load factor or fraction of the annual time the power plant is operating at full capacity and the in-house consumption of electricity.

DPREC Calculates the annual depreciation of the power plant capital assets, including interim capital replacements. The input parameter LL2 selects one of two available options: the straight line method (LL2 = 1) or the sum-of-years-digits method (LL2 = 2).

COSTEG Calculates the unit cost of electricity from the power plant by setting the present worth of the revenues equal to the present worth of the expenses throughout the economic life of the power plant:

$$\text{Unit cost of electricity (mills/kW-hr)} = (\text{present worth of expenses} - \text{present worth of tax credits}) / [(\text{present worth of power production}) * (1 - \text{state gross revenue tax rate}) * (1 - \text{combined federal and state income tax rate})].$$

The present worth of power production takes into account the power plant load factor and the in-house consumption of electricity.

PAYOT Calculates the power plant's annual income statement and annual payout of investments. This includes the total power sales (gross revenues), total tax deductible expenses, taxable income (federal), state and federal income taxes, revenue taxes, and the changes in capitalization: outstanding bonds, bonds repaid, unrecovered equity, equity recovered, bond interest, and earnings on unrecovered equity.

OUTPLT Prints the statements of annual cash flow, tax deductible expenses, income and payout of investments from the beginning of power plant construction through its economic life. The statement of annual cash flow lists the items: year, power plant load factor, capital costs, energy costs from the reservoir, plant operating costs, interim capital replacements, property taxes and insurance, and the sum of these costs. The statement of annual tax deductible expenses lists the items: year, present worth factor for that year, operating expenses, bond interest, depreciation, total deductible operating expenses, and state income taxes. The statement of annual income lists the items: year, million megawatt-hours of electricity produced, power sales, revenue taxes, total tax deductible expenses, taxable income (federal), and federal income tax. The statement of payout of investments lists the items: year, net cash flow,

outstanding bonds, equity capital not recovered, bond interest, earnings on unrecovered equity, bonds repaid, and recovery of equity.

CPOWER Calculates and prints the breakdown of the unit cost of electricity from the power plant in mills/kW-hr and equivalent annual costs in millions of dollars. These are itemized as follows: power plant capital costs, interim capital replacements, energy supply from the reservoir, operating expenses, property taxes and insurance, revenue taxes, state income taxes, federal income taxes, and bond interest. The difference between the unit cost for energy supply at the plant and the unit cost of energy from the reservoir calculated in subroutine COSTEQ is caused by the in-house consumption of electricity. In another set of calculations, the taxes and bond interest are reallocated to the direct cost components for the power plant: capital costs, interim capital replacements, energy supply, operating expenses, and property taxes and insurance.

2.8 STEAM TABLE FUNCTIONS

Tables 2 and 3 give the 1967 ASME Steam Table functions used to calculate thermodynamic and physical properties of water and steam, their arguments, and the temperature-pressure subregions in which they are applicable. The subregions are illustrated relative to the saturation line on the temperature-pressure diagram in Figure 6. Subregion 6 is the area just above and below the saturation line. When calculations of properties are needed near the critical point in subregion 5, the accuracy of the functions used should be checked against the individual requirements since the properties vary rapidly in this area. Definitions for the symbols used in Tables 2 and 3 follow.

- p - Pressure, psia
- t - Temperature, °F
- h - Specific Enthalpy, Btu/lb
- s - Specific Entropy, Btu/lb-F
- v - Specific Volume, ft³/lb

TABLE 2. ASME Steam Table Single Valued Functions

State Unknown
(either wet (two-phase) or superheated)

<u>FORTTRAN</u> <u>Code Name</u>	<u>Function</u>	<u>Subregion</u>
HPS	$h = f(p,s)$	2, 3, 4
SPH	$s = f(p,h)$	2, 3
VPH	$v = f(p,h)$	2, 3
VPS	$v = f(p,s)$	2, 3, 4
TPH	$t = f(p,h)$	2, 3, 4
TPS	$t = f(p,s)$	2, 3, 4
THS	$t = f(h,s)$	2, 3, 4, 6+
PHS	$p = f(h,s)$	2, 3, 4, 6+
XPH	$x = f(p,h)$	
XPS	$x = f(p,s)$	

Saturation Line and Wet Steam

<u>FORTTRAN</u> <u>Code Name</u>	<u>Function</u>	<u>Subregion</u>
HPSW	$h = f(p,s)$	6+
SPHW	$s = f(p,h)$	6+
VPHW	$v = f(p,h)$	6+
VPSW	$v = f(p,s)$	6+
TSL/TSATP	$t = f(p)$	Sat. Line
PHSW	$p = f(h,s)$	6+
PSL/PSATT	$p = f(t)$	Sat. Line

Superheated Steam

HPSD	$h = f(p,s)$	2, 3, 4
HPTD	$h = f(p,t)$	2, 3, 4
SPHD	$s = f(p,h)$	2, 3, 4
SPTD	$s = f(p,t)$	2, 3, 4
VPHD	$v = f(p,h)$	2, 3, 4
VPSD	$v = f(p,s)$	2, 3, 4
VPTD	$v = f(p,t)$	2, 3, 4
TSUPH/TPHD	$t = f(p,h)$	2
TSUPS/TPSD	$t = f(p,s)$	2, 3, 4
THSD	$t = f(h,s)$	2, 3, 4
PHSD	$p = f(h,s)$	2, 3, 4
VISV	$\mu = f(p,t)$	2, 3, 4
CONDV	$k = f(p,t)$	2, 3, 4
PRSTM	$Pr = f(p,t)$	2, 3, 4

Compressed Liquid

HPTL	$h = f(p,t)$	1, 3, 4
SPTL	$s = f(p,t)$	1, 3, 4
VPTL/VCL	$v = f(p,t)$	1, 3, 4
TPHL	$t = f(p,h)$	1, 4
TPSL	$t = f(p,s)$	1, 4
VISL	$\mu = f(p,t)$	1, 2, 3, 4
CONDL	$k = f(p,t)$	1
PRLIQ	$Pr = f(p,t)$	1

Saturated Vapor

HGP	$h = f(p)$	Sat. Line
HGT	$h = f(t)$	Sat. Line
SGP	$s = f(p)$	Sat. Line
SGT	$s = f(t)$	Sat. Line
VGP	$v = f(p)$	Sat. Line
VGT	$v = f(t)$	Sat. Line
PSV	$p = f(s)$	Sat. Line

Saturated Liquid

TSLH	$t = f(h)$	Sat. Line
HFP	$h = f(p)$	Sat. Line
HFT/HSL	$h = f(t)$	Sat. Line
SFP	$s = f(p)$	Sat. Line
SFT/SSL	$s = f(t)$	Sat. Line
VFP	$v = f(p)$	Sat. Line
VFT/VSL	$v = f(t)$	Sat. Line

Some subroutines have been given two names separated by a / mark. When calling these subroutines, the names can be used interchangeably.

TABLE 3. ASME Steam Table Multiple Valued Functions

<u>FORTTRAN</u> <u>Code Name</u>	<u>Function</u>	<u>State</u>
HSSISS	$h, t, v, x = f(p, s)$	Wet or Superheated Steam
HPSISS	$h, t, v, x = f(p, s)$	Superheated Steam
HSS	$h, s, v = f(p, t)$	Superheated Steam
HSV	$h, t, s, v = f(p)$	Saturated Vapor
HCL	$h, s = f(p, t)$	Compressed Liquid
HSSICL	$h, t = f(p, s)$	Compressed Liquid
SSSISS	$s, t, v, x = f(p, h)$	Wet or Superheated Steam
SPSISS	$s, t, v, x = f(p, h)$	Superheated Steam
SSICL	$s, t = f(p, h)$	Compressed Liquid
CRFLO	$fc, \text{ } ^\circ S = f(p, h)$	Wet or Superheated Steam
CRVEL	$Vc, \gamma = f(p, h)$	Wet or Superheated Steam

Isentropic Drop Subroutines

ZSDT	$h_1, s_1, x_1, v_1, t_2, x_2, v_2, h_2$ $= f(p_1, p_2, t_1)$	Wet or Superheated Steam
ZSDH	$t_1, s_1, x_1, v_1, t_2, x_2, v_2, h_2$ $= f(p_1, p_2, h_1)$	Wet or Superheated Steam
ZSRT	$h_1, s_1, t_2, h_2 = f(p_1, p_2, t_1)$	Compressed Liquid
ZSRH	$t_1, s_1, t_2, h_2 = f(p_1, p_2, h_1)$	Compressed Liquid

FIGURE 6. Steam Table Subregions as a Function of Temperature and Pressure

x - Quality by weight fraction, %/100
μ - Viscosity, lb/ft-sec
k - Thermal Conductivity, Btu/hr-ft-F
Pr - Prandtl Number
Vc - Critical Velocity, ft/sec
Fc - Critical Flow, lb/hr-in.²
γ - Isentropic Exponent ($pv^\gamma = \text{Constant}$)
°s - Degrees Superheat

Many of the functions are interdependent. Consequently, if the use of a function is desired the majority of the steam table functions must be loaded into computer memory.

GEOCOST initially calls the following subroutines in the steam tables to initialize steam table constants appearing in labeled common using a series of data statements: CCSR1, CCSR2, CCSR3, CCBLL, and COMALL. These subroutines were converted from original BLOCK DATA subroutines in setting up the steam tables as a user library on the Cyber computer at Battelle-Northwest. The call statements cause the subroutines to be loaded into memory.

3. PREPARATION OF INPUT DATA

3.1 NAMelist INPUT RULES

The first card required in the input data specifies a Hollerith title of 80 characters or less for identifying the simulation printout. The remainder of the data cards permit the user to override default values initialized for the input variables in the BLOCK DATA subroutine. These cards are input using the NAMELIST statement, which permits input of numerical values for variables and arrays preceded by the identifying variable or array names. No format specification is used. This section gives a brief description of the NAMELIST rules for the Cyber computer, which are applicable to most other machines with minor variations. The reader may wish to consult the FORTRAN manual available at his/her installation for a more detailed discussion. A sample case illustrating the NAMELIST input is given in the next section. The reader may find it helpful to refer to the sample input during the following discussion. The definitions of the NAMELIST input variables and their default values in GEOCOST are given following the sample input.

The NAMELIST input in GEOCOST begins in column 2 of the second data card with \$GEOTHM, a NAMELIST group name separated by one or more spaces from the succeeding list of variables, array names, and their numerical values. Input variables and arrays may be defined in three ways.

- variable=constant,
- array name=constant,...,constant,
- array name(integer constant subscript)=constant,...,constant,

Commas separate each definition from succeeding definitions. Constants can be preceded by a repetition number and an asterisk, as for example, array name-3*1.0. This sets the first three locations in the array to the values 1.0. In defining arrays, the number of constants, including repetitions, given for an array name should not exceed the number of elements in the array. The number of elements in the GEOCOST arrays are given accompanying the definition of the input variables and their default values following the

sample input case. When data is input using the definition, array name (integer constant subscript)=constant,...,constant, the array elements are defined consecutively beginning with the location given by the integer constant subscript. The number of constants need not equal, but may not exceed, the remaining number of elements in the array.

Integer or real constants are converted to the type of the variable or array. All input variables in GEOCOST beginning with the letters I through N are integer. All other input variables, except STSEPR which is declared an integer variable in the program, are real.

The variables, array names, and their numerical values succeeding the \$GEOTHM group name are read until another \$ is encountered to complete the definition of the input data for the simulation case. Variables may be in any order. Blanks may be used freely to improve readability except between \$ and GEOTHM, within array names and variable names, and within numerical values. More than one data card is usually needed to define the input data for a simulation case. The first column of each card is ignored and should not contain any data. All cards except the last must end with a constant followed by a comma. The last card must end with a \$ sign.

Consecutive simulation cases can be set up in the input data. Each new simulation case requires the following cards: 1) a title card and 2) a \$GEOTHM card and, when necessary, continuation cards defining the NAMELIST input variables to be changed from the preceding simulation case. The last card for each case must end with a \$ sign. The input data for a simulation case may consist of any subset of the NAMELIST input variables. In setting up consecutive simulation cases in the input data, only the input variables with values differing from the preceding simulation case require redefinition. The values of variables and arrays not included in the input data for a particular simulation case remain unchanged from:

- The default values in BLOCK DATA for the first simulation case.
- The values from the preceding simulation case for cases after the first case.

If no values are to be changed from the default values in BLOCK DATA in the first simulation case, the input data consists of a title card followed by a card with \$GEOTHM \$ beginning in column two.

3.2 INPUT INSTRUCTIONS AND SAMPLE CASE INPUT

The data input to GEOCOST consists of the following two types of cards:

- A title card of 80 characters or less to identify the simulation print-out.
- Data cards defining values for the input variables beginning in column 2 according to NAMELIST input data.

The following steps are suggested for preparing the data input:

- Step 1. Review the NAMELIST input rules summarized in the preceding section.
- Step 2. Prepare a title card of 80 characters or less.
- Step 3. Select values for the technical and economic input variables beginning in column 2 following the NAMELIST input rules. All input variables and their default values are defined in the next section. Those input variables not included in the list of variables in the data cards for a given case are left set to the default values. To aid the user, an overview of the key technical and economic input variables and default values is summarized in Table 4.
- Step 4. Based upon the condition selected for the geothermal fluid at the wellhead, dry steam (STMFR=1.), steam-water mixture ($0 < \text{STMFR} < 1.$), or all water (STMFR=0.), select a steam separation and flashing design option from the seven design options available in GEOCOST shown in Table 5. The values of the input variables required to simulate each steam separation and flashing design are given in Appendix B. The user may wish to execute GEOCOST several times for a given set of technical and economic input conditions by selecting different design options for comparison.

TABLE 4. Key Technical and Economic Input Variables and Default Values

Input Variable	Fortran Name	Default Value	Input Variable	Fortran Name	Default Value
<u>Reservoir Characteristics and Well Properties</u>			<u>Individual Well Drilling Costs</u>		
Well Flow Rate	FLORAT	400,000 lb/hr	Producing Well	DCPW	\$400,000.
Wellhead Temperature	PWTEMP	200°C	Nonproducing Well	DCNPW	\$300,000.
Steam Fraction	STMFRC	0.	Injection Well or Exploratory Well	DCINJW	\$350,000.
Well Life	AVGWL	10 yr			
Well Spacing	WELSPC	20 acres			
<u>Reservoir Financial and Tax Data</u>			<u>Power Plant Financial and Tax Data</u>		
Fraction of Initial Investment in Bonds	DINPUT(4)	0.42	Fraction of Initial Investment in Bonds	DINPUT(39)	0.59
Bond Interest Rate	DINPUT(5)	0.08	Bond Interest Rate	DINPUT(40)	0.08
Equity Earning Rate After Taxes	DINPUT(6)	0.15	Equity Earning Rate After Taxes	DINPUT(41)	0.12
Federal Income Tax Rate	DINPUT(7)	0.48	Federal Income Tax Rate	DINPUT(42)	0.48
State Income Tax Rate	DINPUT(15)	0.07	Power Plant Capacity	DINPUT(43)	55 MWe
Property Tax Rate	DINPUT(17)	0.025	State Income Tax Rate	DINPUT(50)	0.07
Power Plant Operating Life	DINPUT(26)	30 yr	Property Tax Rate	DINPUT(52)	0.025
Royalty Payment	DINPUT(27)	10%	Power Plant Operating Life	DINPUT(61)	30 yr
			Power Plant Load Factor	PF	0.85
<u>Noncondensable Gases in Geothermal Fluid</u>					
Total Weight Percentage of Noncondensable Gases	TOTNCG	0.1%			

TABLE 5. Steam Separation and Flashing Design Options

- Steam Separation at the Wellhead
- Flashing at the Wellhead
- Steam Separation and Flashing at the Wellhead Without Mixing
- Steam Separation and Flashing at the Wellhead With Mixing
- Steam Separation at the Wellhead and Flashing at the Plant
- Steam-Water Mixture with Flashing at the Plant
- Water (No Steam) at the Wellhead and Flashing at the Plant
(Default Design)

To illustrate the input instructions, a sample case input is shown below for simulating the production of electricity from a 210°C, low salinity mixture of steam and water using a steam power conversion cycle.

Sample Case Input

Col. STEAM SEPARATION AND PLANT FLASH
2
\$GEOTHM FLORAT=350000., PWTEMP=210., STMFCR=0.30, DINPUT(43)=55., PRFACT=2.,
STSEPR=0, NFLASH=1, LFLASH=1, LTPHAS=1, INJW=0, INJP=1, IJPUMP=1, IAVWEL=1,
LL6=1 \$

The key technical and economic input conditions selected for defining the reservoir and power plant characteristics are as follows:

Average Flow Rate per Well (FLORAT)	350,000 lb/hr
Temperature (PWTEMP)	210°C
Weight Fraction of Steam (STMFCR)	0.30
Average Well Life (AVGWL, default)	10 yr
Average Well Spacing (WELSPC, default)	20 acres
Power Plant Capacity [DINPUT(43)]	55 MWe
Reservoir Capacity [DINPUT(8), default]	275 MWe
Total Weight Percentage of Noncondensable Gases in the Geothermal Fluid (TOTNCG, default)	0.1%

The steam separation and flashing design selected separates steam, prior to any flashing, from the steam-water mixture at the wellhead for conduction to the plant. The water from the steam separators at the wellheads is conducted to the plant for single-stage flashing at the plant. This option is described as configuration 5 in the appendix (STMFRC=0.30, STSEPR=0, NFLASH=1, LFLASH=1).

The initial steam pressure from the wellhead steam separators is at saturation, prior to degradation during conduction to the plant. The separated steam is conducted to the plant without pumping. Two-phase flow is allowed in the steam pipelines in case small amounts of steam condensate form during the conduction of the steam (LTPHAS=1).

The initial water pressure from the wellhead steam separators is overpressurized by a factor of 2 above saturation (PRFACT=2). The overpressurization is used to avoid two-phase flow due to fluid degradation during conduction to the plant. The overpressurization factor PRFACT is discussed in the appendix for the steam separation and flashing design selected for this sample case: configuration 5 - steam separation at the wellhead and flashing at the plant. The overpressurized water is pumped to the plant as a compressed liquid in a separate transmission line from that of the separated steam.

Prior to entry into the turbine, the separated and flashed steam pass through a water scrubber to remove particulates (ISCRUB=1, default). There is no effluent water from the reservoir to reinject since the water is conducted to the plant for flashing (INJW=0). The effluent water from the plant-located flashers is overpressurized 50 psi above the saturation pressure of the final flash stage and pumped to the reinjection field. The excess water from the plant cooling tower is overpressurized 50 psi above the normal exit pressure of 40 psia and pumped to the reinjection field (INJP=1, IJPUMP=1).

The option to reduce the amount of recomputation in the fluid transmission submodel was selected in computing the geothermal fluid degradation

on a nodal basis (IAVWEL=1). This option takes advantage of the assumption that all wells have the same average properties in the reservoir to speed up the execution time of the fluid transmission submodel.

The option to print only the final iteration between the steam power plant and fluid transmission submodels was selected (LL6=1). The default option to print the full economic output for the reservoir and power plant was used (LL11=1, LL12=1). All reservoir and power plant financial data and tax rates were left set at the default values defined in the next section.

3.3 DEFINITION OF NAMELIST INPUT VARIABLES AND DEFAULT VALUES

This section defines all NAMELIST input variables and default values for GEOCOST. The input variables are grouped into the following categories:

- Reservoir Characteristics and Well Properties
- Well Drilling Costs
- Steam Separation and Flashing Design Options
- Noncondensable Gases
- Fluid Transmission and Disposal
- Steam Power Plant
- Reservoir Financial and Tax Data
- Power Plant Financial and Tax Data
- Reservoir Exploration, Development, and Operation
- Input and Output Options
- Miscellaneous Variables Used Only for Printout Information
 - Well Design and Stratigraphy
 - Fluid Composition

The variables in the categories Well Design and Stratigraphy, and Fluid Composition are required in the extension of GEOCOST which will be released after development and validation are completed. In this version, these variables are used only for informative purposes in the printout.

3.3.1 Reservoir Characteristics and Well Properties

- AVGWL Average production life (years) of reservoir wells. The default is 10 yr.
- FLORAT Flow rate (lb/hr) of the geothermal fluid from the reservoir wellhead. The default is 400,000 lb/hr/well.
- FRCEPW Fraction of excess producing wells to provide spare wells. The default is 0.2.
- FRCNPW Fraction of nonproducing (dry) wells. The default is 0.2.
- PRDRAT Ratio of injection well to producing well flow rate. The default is 2.

PWTEMP Temperature of the geothermal fluid at the reservoir wellhead. Positive input values are treated as Centigrade and negative input values as Fahrenheit. The default is 200°C.

STMFRC Weight fraction of steam in the geothermal fluid at the reservoir wellhead. The default is 0.

WELSPC Reservoir well spacing in acres. The default is 20 acres.

3.3.2 Well Drilling Costs

DCPW Total cost (\$) of all tasks involved in drilling one producing well. The default is \$400,000.

DCNPW Total cost (\$) of all tasks involved in drilling one nonproducing well. The default is \$300,000.

DCINJW Total cost (\$) of all tasks involved in drilling either one exploratory well or one injection well. The default is \$350,000.

PERCNT(N),
N = 1,2 Fraction (not percentage) tangible and intangible parts respectively of the drilling costs for producing wells. The optional breakdown into tangible and intangible parts is provided because of possible differential tax treatment. The tangible part is capitalized and expensed through a depreciation account. The intangible part is expensed immediately. Nonproducing wells are expensed and injection wells are capitalized, with costs recovered through the depreciation account. The default values for the PERCNT array are as follows:

PERCNT(1) = 1/3 fraction tangible,

PERCNT(2) = 2/3 fraction intangible.

3.3.3 Steam Separation and Flashing Design Options

LFLASH Location of flashers:
0, at the wellheads
1, at the plant.
The default location is at the plant.

MIX Option to mix steam separated from the geothermal fluid, if steam is present, with steam obtained from the first flash stage at the wellhead for conduction to the power plant.

0 = no mix

1 = mix separated steam and steam from first flash stage.

The default does not mix the steam obtained from these two sources.

NFLASH Number of successive stages of flashing to be used in flashing water or two-phase mixtures of water and steam to steam. The default is single-stage flashing.

PRFACT Wellhead overpressurization factor (≥ 1 .) provided to:

- 1) set the wellhead pressure of the geothermal fluid at saturation or above, and
- 2) set the water pressure from wellhead steam separators at saturation or above for transmission to the plant and subsequent flashing at the plant.

Subroutine FLASH sets the wellhead pressure based on the scaling factor PRFACT and the saturation pressure corresponding to the input wellhead temperature PWTEMP as follows:

Wellhead Pressure (psia) =

- 1) Pressure at saturation corresponding to the input wellhead temperature when (a) there is steam present to separate from the geothermal fluid at the wellhead ($STMFR > 0$., $STSEPR \neq 0$) or (b) the geothermal fluid is flashed to steam at the wellhead ($LFLASH = 0$, $NFLASH > 0$).
- 2) $PRFACT * (\text{Pressure at saturation corresponding to the input wellhead temperature})$, when there is no steam to separate at the wellhead ($STMFR = 0$., $STSEPR = 1$) and the geothermal fluid (all water) is conducted to the plant for flashing ($LFLASH = 1$, $NFLASH > 0$).

Subroutine DSTEAM sets the water pressure from steam separators at the wellhead when this water is conducted to the power plant, as follows:

PRFACT
(contd)

Water Pressure (psia) from steam separators =

PRFACT * (Pressure at saturation corresponding to the input wellhead temperature), when steam is separated from the geothermal fluid at the wellhead (STMFRC>0., STSEPR=0) and the water from the separators is conducted to the plant for flashing (LFLASH=1, NFLASH>0).

Examples of various steam separation and flashing configurations possible in GEOCOST are in Appendix B. The values of PRFACT and other input variables required to set up each configuration are given to facilitate the preparation of the input data for these variables. The variables include: STMFRC, PRFACT, STSEPR, NFLASH, LFLASH, MIX, LTPHAS, INJW, and INJP. The program user must define the remaining input variables not directly related to setup of the steam separation and flashing configuration to satisfy his/her own case scenario. The default value of PRFACT is 2.

STSEPR Option to separate steam from the geothermal fluid at the reservoir wellhead if steam is present (STMFRC>0.) prior to any flashing.

0 = separation

1 = no separation

The default does not separate the steam. The variable STSEPR is declared an integer variable in the program.

3.3.4 Noncondensable Gases

WPH2S Weight percentage of hydrogen sulphide in the geothermal fluid at the reservoir wellhead. The default is 0.003%.

WPCO2 Weight percentage of carbon dioxide in the geothermal fluid at the reservoir wellhead. The default is 0.097%.

WPCH4 Weight percentage of methane in the geothermal fluid at the reservoir wellhead. The default is 0.

WPONCG Weight percentage of noncondensable gases other than hydrogen sulphide, carbon dioxide, and methane in the geothermal fluid at the reservoir wellhead. The default is 0.

TOTNCG The total weight percentage of noncondensable gases is calculated in subroutine LOAD as the following sum of noncondensable gases:

$$\text{TOTNCG} = \text{WPH2S} + \text{WPCO2} + \text{WPCH4} + \text{WPONCG}.$$

Caution is advised when defining the weight percentage of noncondensable gases in the geothermal fluid. The mass flow rate of geothermal fluid required by the steam power plant is highly sensitive to the total weight percentage of noncondensable gases (TOTNCG). If TOTNCG is excessive, a different gas ejector model is suggested for subroutine GSEJCT. The default value of TOTNCG is 0.1%.

3.3.5 Fluid Transmission and Disposal

CINLAB Cost of labor (\$/ft) for installing pipe insulation in the fluid transmission system. The default is \$4.50/ft.

EVALUE(N),
N = 1,2 Design parameters to change the internal diameters of all pipes in the fluid transmission system in order to alter the pressure degradation. The equations optimizing the internal pipe diameters, both with and without pumping, are programmed in subroutine PIPE. Since EVALUE(N) occurs with an exponent of 0.163 in these equations, an increase (decrease) in EVALUE(N) by a factor of 2, for example, will increase (decrease) the internal pipe diameter by about 12%. EVALUE is an estimate of the value of electrical energy (\$/kW-hr). The EVALUE parameters are implemented on the basis of the fluid type conducted by the pipes:

- 1) EVALUE(1), which has default value of 0.02, is used for pipes conducting water, and
- 2) EVALUE(2), which has default value of 0.015, is used for pipes conducting either steam or two-phase mixtures of steam and water.

IAVWEL Option to speed up the execution time required to calculate the fluid degradation on a node-by-node basis in the transmission system. The execution time for the transmission system can be reduced almost in half for large well fields. This

IAVWEL
(contd)

option activates subroutine STORE, which saves and retrieves variables previously calculated to describe the characteristics of the pipe and fluid exiting from well (nonmanifold) nodes. Provided that all reservoir wells have the same average properties, the characteristics of the pipe and fluid exiting each node in a set of well (nonmanifold) nodes that have the same number of active wells upstream are identical and, therefore, need only be computed once for this set of nodes. This property is illustrated in Section 4.1 describing the sample case output. This option should not be used when inactive well sites are present in the well field matrix or when the wells have variable properties.

0, calculate the fluid degradation individually for each well node.

1, calculate the fluid degradation individually only for those well nodes that have a different number of active wells upstream.

The default option requires more execution time by calculating the fluid degradation individually for each well node.

INJW

Option to reinject the effluent water from stream separators or flashers located at the wellheads.

0 = no reinjection

1 = reinjection

The default is no reinjection since the default design for steam separation and flashing is single-stage flashing at the plant.

INJP

Option to reinject the effluent water from flashers located at the plant and the excess water from the cooling tower.

0 = no reinjection

1 = reinjection

The default is reinjection.

IJPUMP

Option to pump the effluent water from field- or plant-located flashers and excess water from the cooling tower to the injection field(s).

0 = gravity flow

1 = pump

The default uses pumping for reinjection. With gravity flow, the effluent water from the flashers is reinjected at saturation pressure and the excess water from the cooling tower at 40 psia. Pumping increases the pressures by 50 psi. Both the capital cost and internal consumption of electricity of the pumps are calculated.

LTPHAS

Option to permit two-phase flow in the fluid transmission pipes during conduction of geothermal fluid to the power plant.

0, allow single-phase flow only

1, allow two-phase flow

The default allows two-phase flow. An appropriate message is printed when two-phase flow is detected with the option to allow single-phase flow only, and the execution of the case is terminated.

If two-phase flow is to be prohibited, the GEOCOST user has recourse to the following alternatives in the design of the fluid transmission system:

- 1) Change the internal pipe diameter by adjusting the appropriate EVALUE parameter to alter the pressure drop. A penalty resulting from a decrease in the internal pipe diameter is a larger pressure drop, which will result in lower pressure at the turbine inlet.
- 2) Change the flow rate to alter the pressure drop.
- 3) Change the pipe insulation thickness to alter the heat loss.
- 4) Change the nominal external pipe diameter to alter the heat loss.

The last two alternatives require minor reprogramming of sub-routine INSUL for implementation.

- PLINJW Distance (meters) from the reservoir to the injection field. A pipe of this length is used to conduct the effluent water collected from wellhead steam separators or wellhead flashers to the origin of the injection field. The default distance is 1000 m.
- PLINJP Distance (meters) from the power plant to the injection field. Separate pipes of this length are used to conduct the effluent water from the flashing unit located at the plant and the excess water from the cooling tower to the origin of the injection field. The injection field need not be at the same physical location as that used for reinjecting the effluent water from the reservoir. The default distance is 1000 m.
- PSALVG Fraction of transmission or disposal pipe that can be salvaged from a depleted or plugged well and used with a replacement well. This quantity is used in calculating the transmission and disposal interim capital replacement rates, as discussed later in the definition of DINPUT(18) and DINPUT(20). The default value for PSALVG is 0.1.

3.3.6 Steam Power Plant

- B Barometric pressure (in. of Hg), used in calculating the performance of the cooling tower. The default is 29.92 in. of Hg.
- DBAT Dry bulb air temperature (°F), used in calculating the performance of the cooling tower. The default is 70°F.
- WBAT Wet bulb air temperature (°F), used in calculating the performance of the cooling tower. The default is 50°F.
- RI Humidity ratio from the psychrometric chart, used in calculating the performance of the cooling tower. The default is 0.2.
- IPLANT Power plant type. This variable should be left preset to its default value of 2, which specifies a dry or flashed steam power plant.

ISCRUB Option to pass the steam through a water scrubber prior to its entry into the turbine. The water scrubber is presumed to increase the operating life of the turbine by removing the majority of particulates from the steam without significantly degrading the steam quality.

0 = no steam scrubbing

1 = steam scrubbing

The default option scrubs the steam.

PCTS Percent of dissolved solids in the steam. This variable affects the quantity of water required to scrub the steam and the temperature, pressure, and enthalpy of the steam exiting the scrubber. The default is 3%.

PCOND Pressure (psia) specified for the exhaust steam from the turbine. The default is 2 psia.

TCI Cooling water inlet temperature (°F) entering the main condenser, inter- and after-condensers, turbine oil cooler, and generator hydrogen cooler shown in Figure 4, page 13. The default is 80°F.

TCOFT Cooling water exit temperature (°F) from the after-condenser. The default is 120°F.

TCOHC Cooling water exit temperature (°F) from the generator hydrogen cooler. The default is 120°F.

TCOINT Cooling water exit temperature (°F) from the inter-condenser. The default is 110°F.

TCOOC Cooling water exit temperature (°F) from the turbine oil cooler. The default is 120°F.

3.3.7 Reservoir Financial and Tax Data

DINPUT(N), N = 1, ... , 35 is the array of financial and tax data for the reservoir defined below.

N Description of Reservoir Parameters

- 1 Reservoir capital investment (millions of dollars), which is not input directly but calculated in subroutine RESVOR as the following sum: capitalized reservoir exploration costs + tangible part of drilling costs for producing wells + drilling cost of injection wells + capital cost of fluid transmission system + capital cost of fluid disposal system.
- 2 Project life (years) of reservoir and power plant together, which is not input directly but calculated in subroutine RESVOR as the following sum: number of years from the beginning of reservoir exploration to the startup of power plant operation + number of operating years of the power plant, defined in DINPUT(26).
- 3 Not used; default is 0.
- 4 Fraction of initial investment in bonds; default is 0.42.
- 5 Bond interest rate; default is 0.08.
- 6 Earning rate on equity after taxes; default is 0.15.
- 7 Federal income tax rate; default is 0.48.
- 8 Reservoir power level (MWe); default is 275 MWe.
- 9 Depreciable life of reservoir wells (years); default is 10 yr. This is automatically set equal to the average reservoir well life (AVGWL) in subroutine LOAD.
- 10-13 Not used; default is 0.
- 14 Startup year for operation of the power plant; default is 1980.
- 15 State income tax rate; default is 0.07.
- 16 State gross revenue tax rate; default is 0.

- 17 Property tax rate; default is 0.025.
- 18 Transmission system interim capital replacement rate, fraction of transmission capital cost. This rate is not input directly, but calculated in subroutine TRANS as $(1. - PSALVG)/AVGWL$, where PSALVG, input through NAMELIST, is the fraction of transmission pipe that can be salvaged, and AVGWL, input through NAMELIST, is the average reservoir well life (years).
- 19 Property insurance rate; default is 0.0012.
- 20 Disposal system interim capital replacement rate, fraction of disposal capital cost and cost of drilling injection wells. This rate is not input directly, but set equal to the transmission system interim capital replacement rate calculated in subroutine TRANS.
- 21-25 Not used; default values are 0.
- 26 Power plant operating life (years); default is 30 years.
- 27 Royalty payments, percentage of reservoir annual power sales; default is 10%.
- 28 Transmission system maintenance rate, fraction of transmission capital cost; default is 0.05.
- 29 Disposal system maintenance rate, fraction of disposal capital cost; default is 0.05.
- 30-35 Not used; default values are 0.

3.3.8 Power Plant Financial and Tax Data

DINPUT(N), N = 36, ... , 70 is the array of financial and tax data for the power plant defined below.

N Description of Power Plant Parameters

- 36 Power plant capital investment (millions of dollars), which is not input directly, but calculated in subroutine PCONST.

- 37 Project life (years) of power plant, which is not input directly but calculated in subroutine PWRPLT as follows: number of years of power plant construction, input through NAMELIST as NYC, + number of operating years of the power plant, defined in DINPUT(61).
- 38 Not used; default is 0.
- 39 Fraction of initial investment in bonds; default is 0.59.
- 40 Bond interest rate; default is 0.08.
- 41 Earning rate on equity after taxes; default is 0.12.
- 42 Federal income tax rate; default is 0.48.
- 43 Power Plant power level (MWe); default is 55 MWe.
- 44 Depreciable life of power plant (years); default is 30 yr.
- 45-48 Not used; default is 0.
- 49 Start-up year for operation of the power plant; default is 1980.
- 50 State income tax rate; default is 0.07.
- 51 State gross revenue tax rate; default is 0.04.
- 52 Property tax rate, fraction of power plant capital investment; default is 0.025.
- 53 Interim capital replacement rate, fraction of power plant capital investment; default is 0.0035.
- 54 Property insurance rate, fraction of power plant capital investment; default is 0.0012.
- 55-60 Not used; default is 0.
- 61 Power plant operating life (years); default is 30 yr.
- 62-70 Not used; default is 0.
- NYC Number of years to construct the power plant. The default is 3 yr.
- LL2 Depreciation option for recovering the reservoir and power plant capital costs, including interim capital replacements.

1 = straight line

2 = sum-of-years-digits

Default is sum-of-years-digits.

PF Power plant load factor or fraction of the annual time the power plant is operating at full capacity. The default is 0.85.

3.3.9 Reservoir Exploration, Development, and Operation

ACRES Size (acres) of each prospective geothermal site leased for reservoir exploration. This quantity is multiplied by the input unit costs per acre associated with lease procurement (UNITO(N), N = 6, 7, 8 in Tables 6A and 6B) to calculate the lease cost per site. Appendix A contains the cost equations for lease procurement. The default value is 15000 acres.

LAGS (ITEX(N), K), ITEX(N) = 1, ..., 22; K = 1, 2 - Time array to schedule the tasks defining reservoir exploration, development, and operation in Tables 6A and 6B according to costs and the time the tasks are to take place. An internal array in subroutine RESVOR, ITEX(N), N = 1, ..., 39, currently subdivides the 39 tasks in Tables 6A and 6B into 22 subgroups of tasks as shown in Table 7. All tasks within a given subgroup are presumed to occur parallel in time. However, the user has the flexibility to schedule the different subgroups of tasks either sequentially or parallel in time.

The starting month and duration in months (≥ 1) for each set of tasks grouped together are defined by means of the input time array LAGS(ITEX(N), 1) and LAGS(ITEX(N), 2) respectively, indexed by the array ITEX. The starting month for each subgroup of tasks is defined relative to the first task, which is given the base value 0. The starting date for the first task, defining the beginning of reservoir exploration, is back calculated by subroutine RESVOR from the starting date input for the operation of the power plant.

GEOCOST schedules the starting date for the operation of the power plant in January of the year defined in NAMELIST by DINPUT(14). The default value is January, 1980. The back calculation ensures the

TABLE 6A. Tasks and Input Costs for Reservoir Exploration, Development, and Operation

Index for Itemizing Individual Tasks	Index for Grouping Tasks	Description of Grouped Tasks	Unit Costs (Dollars) for (a) Individual Tasks
N	IGP = GROUP(N)	RESERVOIR EXPLORATION TASKS	UNITO(N)
		Identification of Targets	
1	1	Literature Search	100./site
2	2	Preliminary Land Check	250./site
		Preliminary Reconnaissance	
3	3	Literature Search	700./site
4	4	Geological Reconnaissance	1000./site
5	5	Detailed Land Check	1200./site
		Detailed Reconnaissance	
6, 7, 8 ^(b)	6	Lease Procurement	1./acre, 1./acre/year, 2./acre
9	7	Field Geology	5000./site
10	8	Geochemical Examination	5000./site
11, 12 ^(b)	9	Geophysical Examination	4500., 5500./site
		Identification of Drillable Sites	
13	10	Heat Flow Wells (4 per site)	3000./well
14	11	Temperature Gradient Wells (10 per site)	1250./well
15	12	Electrical Resistivity	3500./well
16	13	Microseismic	5000./site
17	14	Detailed Geochemistry	7500./site
		Exploration Drilling	
18, 19, 20, 21 ^(c)	15	Well Drilling	DCINJW/well
22	16	Well Testing	10000./site
		FIELD DEVELOPMENT TASKS	UNITO(N)
23, 24 ^(c)	17	Production Well Drilling	DCPW/well
25 ^(c)	18	Nonproduction Well Drilling	DCNPW/well
26, 27 ^(c)	19	Injection Well Drilling	DCINJW/well
28	20	Transmission System	1.

TABLE 6A. (contd)

Index for Itemizing Individual Tasks	Index for Grouping Tasks	Description of Grouped Tasks	Unit Costs (Dollars) for (a) Individual Tasks
N	IGP = GROUP(N)		
29	21	Disposal System	1.
		FIELD OPERATION TASKS	
30	22	Replacement Well Drilling	1.
31	23	Nonproduction Well Drilling	0.2
32	24	Abandonment	10000./abandoned well
33	25	Well Maintenance	1000./production or injection well
34	26	Overhead and Management	Computed -- Ref. Appendix
35	27	Well Redrilling	5000./production well
36	28	Injection	0.
37	29	Injection Well Maintenance	0.
38	30	Transmission System Maintenance	Computed -- Ref. Appendix
39	31	Disposal System Maintenance	Computed -- Ref. Appendix

(a) NAMELIST input array -- default values.

(b) Tasks done at the same time that were consolidated into one aggregate task as follows:

Lease Procurement

- 6) Bonus payment to leaseholder
- 7) Annual payment to leaseholder
- 8) Administrative procurement cost

Geophysical Examination

- 11) Gravity survey
- 12) Seismic noise

(c) Drilling tasks were also consolidated into aggregate tasks, costed in this version of GEOCOST by means of the following input variables in NAMELIST defining drilling costs for each type of well:

Exploratory Well Drilling

18), 19), DCINJW with default value \$350,000./well
20), 21)

Production Well Drilling

23), 24) DCPW with default value \$400,000./well

Nonproduction Well Drilling

25) DCNPW with default value \$300,000./well

Injection Well Drilling

26), 27) DCINJW with default value \$350,000./well

TABLE 6B. Tasks, Input Times and Success Ratios for Reservoir Exploration, Development, and Operation

Index for Itemizing Individual Tasks	Index for Grouping Tasks	Index for Time Grouping	Start Month Relative to N=1 (a)	Duration in Months(a)	Index for Decision Grouping	Success Ratio(a)	Number of Favorable Sites
N	IGP=GROUP(N)	ITEX(N)	LAGS[ITEX(N),1]	LAGS[ITEX(N),2]	NTARG(N)	FTF[NTARG(N)-1]	FAVSIT(IGP)
1	1	1	0	6	1		128
2	2	↓	↓	↓	↓		↓
3	3	2	1	7	2	0.5	64
4	4	↓	↓	↓	↓		↓
5	5	↓	↓	↓	↓		↓
6,7,8	6	3,3,3	2	11	3	0.5	32
9	7	4	4	10	4	0.67	21
10	8	↓	↓	↓	↓		↓
11,12	9	↓	↓	↓	↓		↓
13	10	5	11	24	5	0.75	16
14	11	↓	↓	↓	↓		↓
15	12	↓	↓	↓	↓		↓
16	13	↓	↓	↓	↓		↓
17	14	↓	↓	↓	↓		↓
18,19,20,21	15	6,6,6,6	23	24	6	0.25	4
22	16	7	47	1	↓	↓	↓
23,24	17	8,8	47	42	7	0.25	1
25	18	9	47	42	↓	↓	↓
26,27	19	10,10	89	27	↓	↓	↓
28	20	11	89	27	↓	↓	↓
29	21	12	89	27	↓	↓	↓
30	22	13	116	348	↓	↓	↓
31	23	14	116	348	↓	↓	↓
32	24	15	116	360	7	0.25	1
33	25	16	116	360	↓	↓	↓
34	26	17	116	360	↓	↓	↓
35	27	18	116	360	↓	↓	↓
36	28	19	116	360	↓	↓	↓
37	29	20	116	360	↓	↓	↓
38	30	21	116	360	↓	↓	↓
39	31	22	116	360	↓	↓	↓

(a) NAMELIST input arrays -- default values.

last task in the reservoir exploration and development ends in the month prior to the starting date input for the operation of the power plant. With the default values, this date is December, 1979.

The default values shown for the starting months for all tasks included in reservoir operation are defined relative to the first task in reservoir exploration so as to coincide with the startup date input for the operation of the power plant. However, regardless of the starting months specified for the tasks in the reservoir operation, subroutine RESVOR schedules the starting months to coincide with the startup date input for the operation of the power plant. Similarly, regardless of the duration in months specified for the tasks in the reservoir operation, subroutine RESVOR schedules the duration based upon the operating life of the power plant. Table 7 lists the subgrouping of the tasks presumed to occur parallel in time by the array ITEX and the default values of the array LAGS.

TABLE 7. Subgrouping of Reservoir Tasks Occurring Parallel in Time

	<u>Reservoir Exploration</u>																					
Task N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
ITEX(N)	1	1	2	→		3	→		4	→	→	→	5	→	→	→	→	6	→	→	→	7
LAGS[ITEX(N), 1]	0			1			2					4					11				23	47
LAGS[ITEX(N), 2]	6			7			11					10					24				24	1

<u>Reservoir Development</u>							
Task N	23	24	25	26	27	28	29
ITEX(N)	8	8	9	10	10	11	12
LAGS[ITEX(N), 1]	47	47		89	89	89	
LAGS[ITEX(N), 2]	42	42		27	27	27	

	<u>Reservoir Operation</u>									
Task N	30	31	32	33	34	35	36	37	38	39
ITEX(N)	13	14	15	16	17	18	19	20	21	22
LAGS[ITEX(N), 1]	116	116	116	116	116	116	116	116	116	116
LAGS[ITEX(N), 2]	348	348	360	360	360	360	360	360	360	360

The time sequences of the tasks corresponding to the default values of the LAGS array and default power plant startup date of January, 1980 are delineated in the bar graph of Figure 7. A discussion of the use of these arrays in subroutine RESVOR is in the appendix.

UNITO(N), N = 1, ..., 39 - Cost array defining costs (dollars) for the tasks in the exploration, development, and operation of the reservoir on a unit basis, primarily per target site, acre, or well, based upon industry estimates. The total cost associated with each task is calculated in subroutine RESVOR by multiplying the appropriate unit cost in the UNITO array by the number of favorable target sites, acres, or wells calculated by GEOCOST for that task. The cost equations based on the UNITO array are given in Appendix A. The default values for the UNITO array are shown for each of the reservoir tasks in Table 6A.

FTF[NTARG(N) - 1], NTARG(N) = 1, ..., 7 - Success ratios, indexed by the array NTARG(N), associated with the major decision points in the step-by-step process of reducing the number of prospective reservoir sites. The process converges on one site for development and operation. An internal variable NUMFTF in subroutine RESVOR currently sets the number of major decision points in the reservoir exploration process to six. An internal array, NTARG(N), N=1,...,39, subdivides the 39 tasks in Table 6B into 7 series of tasks (one more than the number of decision points) according to the major decision points. Appendix A has a description of the calculation by GEOCOST of the initial number of target sites to identify for exploration and number of sites to retain at each decision point for further exploration based upon the success ratios FTF[NTARG(N) - 1]. Table 8A shows the subgrouping of the tasks by the array NTARG, the corresponding decision points and the default values of the array FTF. Table 8B describes the decision points.

FIGURE 7. Default Time Sequence of Reservoir Exploration, Development, and Operation Tasks

TABLE 8A. Subgrouping of Reservoir Tasks by Decision Points

Task N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17						
NTARG(N)	1	1	2	→		3	→		4	→			5	→									
NTARG(N)-1=					1		2					3					4						
Decision Point																							
FTF[NTARG(N)-1]					0.5		0.5					0.67					0.75						
Task N	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	
NTARG(N)	6 →					7 →																	
NTARG(N)-1=					5																	6	
Decision Point																							
FTF[NTARG(N)-1]					0.25																	0.25	

TABLE 8B. Description of Decision Points

Decision Point	Description
1	Fraction of sites to retain for preliminary reconnaissance after identification of target sites
2	Fraction of sites to lease after preliminary reconnaissance
3	Fraction of leased sites to retain for detailed reconnaissance
4	Fraction of sites to evaluate for subsequent exploratory drilling
5	Fraction of sites to retain for exploratory drilling
6	Fraction of sites to develop and operate

3.3.10 Input and Output Options

ICASE Input option to generate consecutive cases automatically in subroutine GCASE as combinations of multiple input values for each of the parameters: wellhead temperature (°C), wellhead flow rate (lb/hr), power plant size (MWe), well spacing (acres), and well life (years). This option is provided to reduce the number of title and NAMELIST input cards to prepare when the different cases

represent a large number of combinations of values for the above parameters. Use of this input option requires additional data cards following the NAMELIST input cards. These cards are defined following the description of the NAMELIST input variables.

0 = no case generation

1 = case generation

The default is no case generation.

LL6 Print switch for selecting the power plant and fluid transmission iteration history, essentially comprising the technical, as opposed to economic, output from GEOCOST.

0, suppresses printout of the iterations

1, prints only the last iteration upon convergence

2, prints all iterations

Default suppresses all iteration printout.

LL11, LL12 Print switches for selecting the reservoir and power plant economic printout.

LL11 = 1, LL12 = 1, prints all economic output

LL11 = 1, LL12 = 0, prints an economic summary of the reservoir and power plant, including the breakdown of power costs from the reservoir and power plant, but excluding the statements of annual cash flow, tax deductible expenses, income, and payout of investments.

LL11 = 0, LL12 = 0, suppresses all economic output.

Default is full economic printout.

3.3.11 Miscellaneous Variables Used Only for Printout Information

3.3.11.1 Well Design and Stratigraphy

CASFRC Fraction of each producing well cased. The default cases the entire well depth.

DIA Average diameter (centimeters if positive, inches if negative) of the reservoir wells to be drilled. The default is 22.225 centimeters.

NUMTYP Number of different generic types of rock hardness comprising the strata encountered in drilling the entire depth of each reservoir well. The variable NUMTYP should be left preset to its default value of 1, indicating one hardness for the entire depth of the well.

STRATA(M,N), M = 1,2; N = 1,...,10 - Stratigraphic data array defining the type of rock hardness to be drilled (M = 1) and the depth (M = 2, positive if meters, negative if feet) of each type of strata (N) encountered in drilling the reservoir wells. The possible values of STRATA(1,N) are as follows:

1 = soil, 2 = soft, 3 = medium, 4 = hard, and 5 = very hard:

The default values are as follows:

STRATA(1,1) = 4, indicating that the rock type to drill is "hard" for the entire depth of the well.

STRATA(2,1) = 2000., total well depth in meters.

3.3.11.2 Fluid Composition

CAC03 Weight percentage of calcium carbonate in the geothermal fluid at the reservoir wellhead. The default is 0.

WPDS Weight percentage of salt in the geothermal fluid at the reservoir wellhead. The default is 3%.

ODS Weight percentage of dissolved solids, other than calcium carbonate, salt, and silicon dioxide, in the geothermal fluid at the reservoir wellhead. The default is 0.

PH The pH factor of the geothermal fluid at the reservoir wellhead. The default is 7, indicating a neutral solution.

3.4 CONSECUTIVE CASE GENERATION INPUT OPTION

As discussed in the NAMELIST input rules, consecutive simulation cases can be set up using NAMELIST input. Each new case requires the following cards: 1) a title card and 2) a \$GEOTHM card and, when necessary, continuation cards defining the NAMELIST input variables to be changed from the preceding simulation case. The last card for each case ends with a \$ sign. As an alternative option defined by setting ICASE = 1 in the NAMELIST input, consecutive cases can be generated automatically in GEOCOST as combinations of key case generation variables. An array of numerical values is input for each of the case generation variables. GEOCOST then generates consecutive simulation cases as combinations of these values from the input arrays for the case generation variables. This reduces the number of title and NAMELIST cards that the user must prepare. Use of the case generation option requires the following set of cards.

- Title card
- NAMELIST input cards beginning in column 2 with \$GEOTHM on the first NAMELIST input card
- Case generation cards, prepared according to the appropriate format specifications, which provide the following information:
 - Index of the starting element in an array of numerical values for each case generation variable to use in generating combinations (one card with format 5I1)
 - Size of the array for each case generation variable (one card with format 5I1)
 - Hollerith titles identifying the array of numerical values for each case generation variable (one card for each variable with format 8A10)
 - Array of numerical values for each case generation variable (one card for each variable with format 8F10.0)

All case generation variables are omitted from the NAMELIST input cards since they are defined using the case generation cards. Five items frequently varied in parametric studies comprise the case generation variables. The variables in order of definition on the case generation cards are:

- 1) Wellhead Temperature ($^{\circ}\text{C}$)
- 2) Average Flow Rate per Well (lb/hr)
- 3) Power Plant Capacity (MWe)
- 4) Average Well Spacing (acres)
- 5) Average Well Life (years)

This order of definition must be retained throughout the case generation cards. Other items could be selected as case generation variables with minor modifications of the code in subroutine GCASE.

To illustrate the case generation input, the sample case previously illustrated using NAMELIST input is shown below using the case generation input option.

	<u>Sample Case Input Using Case Generation Input Option</u>		
	Cols.		
	12345678910		
Title Card	SAMPLE		
NAMELIST Cards	\$GEOTHM STMFRC=0.30, PRFACT=2., STSEPR=0, NFLASH=1, LFLASH=1, LTPHAS=1, INJW=0, INJP=1, IJPUMP=1, IAVWEL=1, LL6=1, ICASE=1 \$		
Starters	11211		
Array Sizes	31311		
Titles	TEMP=210C TEMP=220C TEMP=250C		
	FLOW=350K		
	MWE = 55 MWE = 75 MWE = 110		
	WACRES=20		
	WLIFE =10		
Numerical Arrays	210.	220.	250.
	350000.		
	55.	75.	110.
	20.		
	10.		

With the case generation option, the title card preceding the NAMELIST input should be limited to descriptive Hollerith information in the first 10 columns. The remainder of the title appearing in the simulation printout is set up in GEOCOST as appropriate combinations of the titles in the case generation cards.

The first card following the NAMELIST data specifies the first position in each array of values to be used in setting up the parametric combinations of case generation variables. In most situations, the user will want to specify that the parametric combinations be set up starting with the first element in each array (11111). However to show the flexibility of the case generation option, the sample case specifies that the combinations be set up starting with the first elements of the 1st, 2nd, 4th, and 5th arrays and the second element of the third array (11211). With these starting values, the first parametric combination will be as follows:

Wellhead Temperature	210°C
Average Flow Rate per Well	350,000 lb/hr
Power Plant Capacity	75 MWe
Average Well Spacing	20 acres
Average Well Life	10 yr

The first element in the power plant capacity array will not appear in any case combination since the starting element is the 2nd value in the array.

The second card defines the size of the array of numerical values for each case generation variable (31311).

The next set of five cards, one card per variable, lists titles to associate with the different values for each case generation variable. The titles on these cards are used in GEOCOST to set up the remaining title after the first 10 columns in the main title card to identify the simulation cases generated from the combination of values for the case generation variables.

The final set of five cards, one card per variable, defines the array of multiple input values for each case generation variable used in generating parametric combinations. In generating case combinations, the last

case generation variable (average well life) is varied most rapidly over its range of values. The first case generation variable (wellhead temperature) is varied least rapidly.

The consecutive simulation cases generated by the sample input data are listed in order below. For the sake of brevity, the generated cases are described by listing the titles generated in GEOCOST for each case:

- 1) SAMPLE TEMP=210C FLOW=350K MWE= 75 WACRES=20 WLIFE=10
- 2) SAMPLE TEMP=210C FLOW=350K MWE=110 WACRES=20 WLIFE=10
- 3) SAMPLE TEMP=220C FLOW=350K MWE= 75 WACRES=20 WLIFE=10
- 4) SAMPLE TEMP=220C FLOW=350K MWE=110 WACRES=20 WLIFE=10
- 5) SAMPLE TEMP=250C FLOW=350K MWE= 75 WACRES=20 WLIFE=10
- 6) SAMPLE TEMP=250C FLOW=350K MWE=110 WACRES=20 WLIFE=10

4. DESCRIPTION OF OUTPUT RESULTS

4.1 DESCRIPTION OF SAMPLE CASE OUTPUT

Appendix D lists the computer output generated by the sample case described previously, illustrating the input data using NAMELIST. The 32 pages of printout show the output for the final iteration between the steam power plant and fluid transmission submodels (LL6=1) and the full output from the reservoir and power plant economic submodels (LL11=1, LL12=1). The output results are printed in an easy-to-read format with an accompanying description. Table 9 presents an overview of the output, identifying the pages of output generated by the major submodels in GEOCOST. For the sake of brevity, a more detailed description is provided below only for output results that require further elucidation.

The output from the final iteration of the steam power plant submodel is shown on pages D.1 and D.2 including information on:

- Separation of steam from a steam-water mixture and flashing of the water from the steam separators using wellhead conditions.
- Steam power plant input conditions.
- Extraction of noncondensable gases.
- Steam requirements of the turbine.
- Cooling water requirements.
- Cooling tower performance calculations.
- Internal power requirements.
- Overall results for the steam power plant.

The following discussion focuses upon the results from subroutine FLASH. The steam separation and flashing design selected in the input data simulates separation of steam from a steam-water mixture at the wellhead and flashing of the water from the wellhead steam separators at the plant (configuration 5 in Appendix B). The input to subroutine FLASH on page D.1 describes the initial conditions of the steam-water mixture at the wellhead. The steam

TABLE 9. Summary of Computer Output from GEOCOST

<u>Description of Output</u>	<u>Pages D</u>
<u>Steam Power Plant and Fluid Transmission Iteration History</u> <u>(Final Iteration)</u>	1 - 17
• Steam Power Plant Submodel Input and Output	1 - 2
• Fluid Transmission Submodel Input	3
• Fluid Transmission Submodel Output	4 - 11
• Plant Flash for Final Iteration, Steam Scrubber Submodel, and Convergence Test for Steam Power Plant and Fluid Transmission Iteration	11 - 13
• Injection Submodel Output	13 - 17
<u>Reservoir Technical and Economic Input and Output</u>	18 - 25
• Reservoir Characteristics, Well Properties, and Noncondensable Gases	18
• Reservoir Exploration, Development, and Operation Costs	19
• Financial and Tax Data Input	20
• Annual Cash Flow Statement	21
• Annual Tax Deductible Expense Statement	22
• Annual Income Statement	23
• Annual Payout of Investments (Capitalization)	24
• Summary Breakdown of Cost of Energy from Reservoir	25
<u>Plant Economic Input and Output</u>	26 - 32
• Capital Cost Output	26
• Financial and Tax Data Input	27
• Annual Cash Flow Statement	28
• Annual Tax Deductible Expense Statement	29
• Annual Income Statement	30
• Annual Payout of Investments (Capitalization)	31
• Summary Breakdown of Cost of Power from Plant	32

power plant submodel initially calculates the total fluid flow requirements for the power plant based on the wellhead conditions. The output from subroutine FLASH on page D.1 shows the temperature, pressure, enthalpy, and mass fraction of the steam obtained by steam separation and flashing of the water from the wellhead steam separators prior to degradation in the fluid transmission submodel.

After the initial iteration between the steam power plant and fluid transmission submodels, the total fluid flow requirements for the power plant are calculated based on the degraded fluid conditions transmitted by the fluid transmission submodel. The separated steam at the wellhead is degraded during conduction to the plant. After separation at the wellhead, the water is also degraded during conduction to the plant, where it is flashed to steam. The temperature, pressure, enthalpy, and mass fraction of the steam obtained by flashing the degraded water at the plant is shown for the final iteration of the fluid transmission submodel in the output from subroutine FLASH on page D.11.

The input conditions to the fluid transmission submodel are on page D.3. The output from the final iteration of the fluid transmission submodel is on pages D.4-D.11. The separated steam at the wellhead is conducted to the plant in transmission line 1. The water separated at the wellhead is overpressurized and pumped to the plant in transmission line 2 for flashing at the plant. After separation the water is overpressurized by a factor of 2 above saturation for the first iteration of the fluid transmission submodel. As discussed in Appendix B for steam separation and flashing configuration 5, the overpressurization factor is minimized by making two passes through the fluid transmission submodel during the first iteration between the steam power plant and fluid transmission submodels. The minimized overpressurization factor of 1.08 used in subsequent iterations is still sufficient to prevent the water from entering into two-phase flow in the pipeline during conduction to the plant. Table 10 summarizes the degradation of the steam and water during conduction from the wellhead to the plant for the final iteration of the fluid transmission submodel.

TABLE 10. Fluid Transmission Lines from the Reservoir to the Power Plant

Steam-Water Mixture at Wellhead

Total Flow Rate: 2,267,260 lb/hr Steam Fraction: 0.30

<u>Location</u>	<u>Temperature</u>			<u>Pressure</u>			<u>Enthalpy</u>											
	(°F)			(psia)			(Btu/lb)											
	410.			276.7			630.8											
	<u>Line 1 -- Separated Steam</u>						<u>Line 2 -- Water from Steam Separators</u>											
	Flow Rate: 680,178 lb/hr						Flow Rate: 1,587,082 lb/hr											
	<u>Temperature</u>			<u>Pressure</u>			<u>Enthalpy</u>			<u>Temperature</u>			<u>Pressure</u>			<u>Enthalpy</u>		
	(°F)			(psia)			(Btu/lb)			(°F)			(psia)			(Btu/lb)		
Wellhead	410.			276.7			1202.1			410.			299.2			386.		
	↓ Fluid Transmission Degradation						↓ Fluid Transmission Degradation											
	↓ Steam Condensate from Two-Phase Flow Removed at Plant												↓					
Flasher Inlet at Plant										409.2			283.7			385.1		
													<u>Flashed Steam from Plant-Located Flasher</u>					
													Flow Rate: 252,614 lb/hr					
Scrubber Inlet at Plant	401.4			251.3			1201.2			267.6			40.3			1170.		
Scrubber Exit into Plant	393.8			230.2			1200.1			263.			37.3			1168.4		

Degradation of the steam and water during conduction is shown on a node-by-node basis on pages D.4-D.10. The steam degradation on pages D.4-D.7 is used as an example in the following discussion to clarify this output. Figure 8 shows the pressure degradation in the steam line on a node-by-node basis, corresponding to the output on pages D.4-D.7.

The layout of the nodes in the well field design is shown on pages D.5 and D.9 and illustrated in Figure 8, page 74. The well field is depicted in the 4th quadrant of a Cartesian coordinate system with origin at the plant. The previous representation in Figure 5, page 16, showed the well field in the 1st quadrant. However, the concepts and results are independent of the quadrant used in representing the well field layout.

The routing of the steam transmission line is shown in Figure 8. The pipe runs are parallel to the horizontal X-axis, joining with one steam manifold line leading to the plant. The steam degradation is calculated in the order shown on page D.4, beginning with the perimeter well node ($I=4, J=2$) and proceeding downstream to the plant.

The output from the first iteration at a node (iteration 1 on page D.4) shows the condition of the steam exiting the node. The letter M is used to indicate the mixture of two inlet flows of steam at a node:

- Steam exiting a well node ($J>1$ in Figure 8) is a mixture of separated steam from the wellhead and degraded steam transmitted from upstream well nodes.
- Steam exiting a manifold node ($J=1$ in Figure 8) is a mixture of degraded steam from the upstream manifold line and degraded steam from the row of wells leading into the manifold node.

The exit enthalpy is a mass-weighted average of the inlet enthalpies. The exit pressure is the lower of the two inlet pressures. The exit steam fraction is calculated using the steam library function XPHH, based upon the exit pressure and exit enthalpy. The exit temperature is calculated using the steam library functions based upon the exit pressure, enthalpy, steam fraction, and fluid state.

FIGURE 8. Well Field Nodes and Steam Pressure Degradation on a Nodal Basis

The output from the last iteration at a node (iteration 3 on page D.4) shows the degraded condition of the steam immediately prior to its entry into the next downstream node. Steam degradation between neighboring nodes is a function of the internal pipe diameter. Inversely, the optimization algorithm used in the fluid transmission submodel to calculate the internal pipe diameter is a function of the mass flow rate and steam conditions. The initial estimate of the internal pipe diameter is calculated assuming no steam degradation between neighboring nodes. The steam degradation is then calculated as a function of the internal pipe diameter. Using the degraded steam conditions, the internal pipe diameter is recalculated. The process iterates until the degraded steam temperature at the entry into the downstream node changes by less than 0.10°F from the temperature calculated in the previous iteration. The internal diameters of the steam pipes are shown on a node-by-node basis on pages D.4 and D.6.

The condensed output on page D.4 for nodes with 0 iterations lists only the degraded steam conditions immediately prior to entry into the next downstream node. Well nodes with 0 iterations reflect the savings in nodal computations obtained by setting the input option IAVWEL = 1. This option takes advantage of the property that well nodes with the same number of upstream wells have identical inlet and exit fluid conditions, provided that all wells in the well field have identical flow rates and fluid conditions. The well nodes can be grouped according to the number of upstream wells shown for each node on pages D.5 and D.9 as follows:

<u>Number of Upstream Wells</u>	<u>Well Node Identification Number</u>
1	5,6,7,8
2	2,3,4
3	1

The number of well nodes that require recomputation can thus be reduced from 8 to 3 nodes. This reduction in recomputation cannot be extended to manifold nodes which are all individually computed. In addition, the reduction in computation cannot be used if the wells have variable flow rates or variable fluid conditions.

As shown on page D.4, the steam separated at the wellhead entered into two-phase flow during conduction. The steam condensate was removed prior to entry into the plant. The condensation amounted to a loss of 1,320 lb/hr of steam. This loss represented only 0.14% of the total steam requirement of 932,792 lb/hr shown on page D.13 and was assumed to be insignificant. Consequently, no additional geothermal flow from the wellhead was provided by the fluid transmission submodel to compensate for the small amount of steam lost by condensation.

In general, the steam quality in steam pipelines during two-phase flow has exceeded 0.99 weight fraction over a large range of data cases. Thus, the amount of steam that condenses in two-phase flow is usually insignificant in relation to the total amount of steam demanded by the power plant. If the steam condensate exceeds 1% of the total steam requirements of the power plant, a message is printed cautioning the user that no additional geothermal flow is provided to compensate for the loss of steam by condensation. In this event, the degradation of the steam quality and amount of condensation can be altered by selecting values for EVALUE(2) other than the default value of 0.015. The parameter EVALUE(2) represents a design parameter that can be used to change the diameter of steam pipelines.

The output from the fluid disposal submodel is shown on pages D.13-D.17. The condition and flow rates of the excess water from the plant cooling tower and the effluent water from the plant-located flasher used in reinjection are summarized in Table 11. In this version of GEOCOST, fluid degradation is not simulated in the reinjection lines.

The capital costs for the fluid transmission and disposal systems are shown cumulatively in the simulation printout. The capital costs for transmission line 2 on page D.11 include the capital costs for transmission lines 1 and 2. Similarly, the capital costs for reinjection line 2 on page D.17 include the capital costs for reinjection lines 1 and 2.

The output from the reservoir economic submodel is on pages D.18-D.25. Page D.18 lists the characteristics of the reservoir, properties of the wells, and total noncondensable gases in the geothermal fluid. The output

TABLE 11. Fluid ReInjection Lines from the Power Plant to the Injection Field

Line 1 -- Excess Water from Power Plant Cooling Tower

Flow Rate	222,183 lb/hr
Temperature	80°F
Pressure	90 psia

Line 2 -- Effluent Water from Plant-Located Flasher

Flow Rate	1,334,468 lb/hr
Temperature	267.6°F
Pressure	90.3 psia

listed under well properties includes the following information; descriptions of the calculation of these quantities are in succeeding paragraphs.

- 1) Number of producing wells
- 2) Number of nonproducing (dry) wells
- 3) Number of injection wells
- 4) Thermal energy per well
- 5) Gross electrical power per well
- 6) Net electrical power per well
- 7) Actual flow rate per well

- 1) Number of producing wells =

$\{[\text{total flow rate (lb/hr) demanded by the power plant}]/\text{maximum flow rate (lb/hr) per well}\} * (1. + \text{fraction of excess producing wells})$

where:

fractional results are rounded up to the next largest integer.

the maximum flow rate per well is input as the variable FLORAT.

the fraction of excess producing wells is input as the variable FRCEPW.

- 2) Number of nonproducing (dry) wells =

$(\text{number of producing wells}) * (\text{fraction of nonproducing wells})$

where:

fractional results are rounded to the nearest integer.

the fraction of nonproducing wells is input as the variable FRCNPW.

3) Number of injection wells =

number of injection wells based upon the effluent water from flashers or separators + number of injection wells based upon the excess water from the plant cooling tower

These quantities are calculated as follows:

- Number of injection wells based upon the effluent water from flashers or separators = $\frac{\text{effluent water flow rate (lb/hr) from flashers or separators}}{\text{maximum injection well flow rate (lb/hr)}}$

where:

fractional results are rounded to the next largest integer.

the maximum injection well flow rate = (ratio of injection well to producing well flow rate, input as PRDRAT) * (maximum producing well flow rate, input as FLORAT).

- Number of injection wells based upon the excess water from the plant cooling tower = $\frac{\text{excess water (lb/hr) from the plant cooling tower}}{\text{maximum injection well flow rate (lb/hr)}}$

where:

fractional results are rounded to the next largest integer.

4) Thermal energy (MWt) per well =

$[\text{maximum flow rate (lb/hr) per well}] * (\text{enthalpy at the wellhead} - \text{enthalpy at the exit from the cooling tower}) / (3.41443 * 10^6)$

5) Gross electrical power (MWe) per well =

$\text{power plant capacity (MWe)} / \text{number of producing wells}$

6) Net electrical power (MWe) per well =

$\text{net power plant output (MWe)} / \text{number of producing wells}$

7) Actual flow rate (lb/hr) per well =

total flow rate (lb/hr) required by the power plant / number of producing wells.

The direct expenses associated with reservoir exploration, development and operation are on page D.19. Page D.20 contains the financial and tax input data for the reservoir and case identification information. Annual cash flow data for the major reservoir expenses are on page D.21; summary accounts of deductible expenses are on page D.22. A simplified income statement is on page D.23 and the net cash flow and investment position are on page D.24.

The cost of energy for the reservoir is summarized on page D.25. The unit cost of energy for this sample case is 8.5 mills/kW-hr. The equivalent annual cost during the operating life of the power plant is \$3,471,000. In the right-hand column labeled distribution of energy costs, the taxes, royalty payments, and bond interest are reallocated to the direct cost components for the reservoir. The rate of return on investment is included in the distributed energy cost for each component. The deductible nature of bond interest causes this expense to be partially included in the rate of return (the part which is included in the present worth factor) and the remainder to be accounted for separately.

The output from the power plant economic submodel is on pages D.26-D.32. Page D.26 lists the power plant capital costs. Pages D.27-D.31 contain the same economic and accounting information for the power plant as pages D.20-D.24 for the reservoir. The cost of power for the power plant is summarized on page D.32. The unit cost of power for this sample case is 15.4 mills/kW-hr. The equivalent annual cost during the operating life of the power plant is \$6,086,000. All costs from the reservoir are included in the energy supply cost item. The energy supply costs are derived from the energy cost account on page D.28. The energy cost account is identical to the total power sales from the reservoir on page D.23. The difference between the unit cost for energy supply at the plant and the unit cost of energy from the reservoir is caused by the in-house consumption of electricity.

Unit cost of energy supply at power plant = Unit cost of energy

supply at reservoir * $\frac{\text{gross output (MWe) of power plant}}{\text{net output (MWe) of power plant}}$

The potential savings in the cost of power from the power plant if the in-house consumption of electricity were reduced to 0 for this sample case is 0.60 mills/kW-hr or \$236,000/yr during the operating life of the power plant. As with the reservoir cost distribution, the taxes and bond interest are reallocated to the direct cost components in the right-hand columns of the cost distribution.

4.2 CYBER COMPUTER COMPILATION AND EXECUTION TIMES

The GEOCOST and Steam Library FORTRAN code required 2-1/2 minutes to compile with the FTN version 4.2 compiler at optimization level 1 on the Cyber 74-18 computer with Scope 3.4.2 operating system. The sample case described in the previous section required 36 seconds of CPU time for execution. The execution time is principally dependent upon the number of wells and fluid transmission lines required to supply the mass flow rate of geothermal fluid needed by the steam power plant submodel. This follows from the fact that the fluid transmission submodel calculates the conduction and degradation of the geothermal fluid on a node-by-node basis for each fluid transmission line from the reservoir to the power plant. The number of wells depends upon many factors, including:

- Wellhead temperature
- Fluid condition (water, steam, or steam-water mixture)
- Well flow rate
- Noncondensable gas content
- Fluid degradation during conduction to the power plant
- Number of flashing stages
- Power plant size

5. CONTROL CARDS

5.1 MINIMAL CONTROL CARD REQUIREMENTS

The GEOCOST program can be converted to the user's computing facilities with a minimal set of basic control cards necessary to compile, load and execute a FORTRAN source program available on tape. One disk file (TAPE11 below) is used internally in GEOCOST to store summary printout obtained with the case generation input option. In order to execute GEOCOST, it is necessary to compile and load all GEOCOST subroutines and the following steam table subroutines:

STEAM TABLE SUBROUTINES REQUIRED BY GEOCOST

CCSR1	GR1	HSV	SPT2	VFT
CCSR2	GRS	HVT3	SPTL	VISL
CCSR3	HCL	P23T	STER	VPH
CCBLL	HPS	PSL	SVT3	VPT1
COMALL	HPT1	PSV	TPS	VPT2
COMT1	HPT2	PVT3	TPSL	VPT3
COMT2	HPTL	SPH	TSL	VPTD
COMT3	HSS	SPT1	TSLH	VPTL

The object code generated by compiling the GEOCOST and steam table subroutines can be stored on disk as a sequential file or as a random library file. The file containing the object code can be subsequently attached and loaded for executing input data sets.

5.2 CYBER COMPUTER CONTROL CARDS ILLUSTRATING THE USE OF PROGRAM AND USER LIBRARIES WITH GEOCOST

This section illustrates a more elaborate set of control cards used with the Cyber computer at Battelle-Northwest for updating and executing GEOCOST with program and user libraries. The source code for GEOCOST was maintained on a disk file called GEOTHERMALSRC, organized as a random program library using UPDATE software. The object code for GEOCOST and the 1967 ASME Steam Library was maintained on a disk file called GEOTHERMALIB, organized as a random user library using EDITLIB software.

Four small, compiled drivers were maintained on separate disk files to load the subset of GEOCOST subroutines required to simulate four different types of power plants: steam, binary fluid, total flow, and geopressured reservoirs. The choice of a user library for the object code provided a convenient means for loading into computer memory only the subset of GEOCOST and steam library subroutines required to simulate the particular type of power plant selected. In this version of GEOCOST, which simulates only the steam power plant, the corresponding driver simplifies to the following code on the Cyber, which was maintained on a disk file called GEOCOSTSTEAM:

```
PROGRAM GEOCOST (INPUT, OUTPUT, TAPE5 = INPUT, TAPE6 = OUTPUT,  
    TAPE11)  
CALL HOTROK  
STOP  
END
```

With this background of the file structure at Battelle-Northwest in perspective, the set of control cards in Table 12 specifies the following sequence of job steps used to update and execute GEOCOST:

- Attach the disk file GEOCOSTSTEAM, containing the compiled driver for selecting the steam power plant.
- Attach the disk file GEOTHERMALSRC of GEOCOST source subroutines, organized into a random program library using UPDATE.
- Attach the disk file GEOTHERMALIB of compiled GEOCOST and steam library subroutines, organized into a random user library using EDITLIB.
- Modify the program library using UPDATE, putting only the modified source subroutines on the compile file.
- Catalog the newly updated program library.
- Purge the old program library.
- Compile the modified source subroutines.
- Extend the user library using EDITLIB to incorporate the compiled subroutines that were modified.

TABLE 12. Control Cards to Update, Compile, Load, and Execute GEOCOST on the Cyber Computer

Installation Job Card

Installation Account Card

ATTACH(GEOCOST,GEOCOST\$TEAM,ID=X,PW=X)

ATTACH(OLDPL,GEOOTHERMAL\$SRC,ID=X,PW=X)

ATTACH(LIB,GEOOTHERMAL\$LIB,ID=X,PW=X)

LIBRARY(LIB)

REQUEST(NEWPL,*PF)

RFL(40000)

UPDATE(E,N)

RETURN(OLDPL)

CATALOG(NEWPL,GEOOTHERMAL\$SRC,RP=999,ID=X,PW=X)

RETURN(NEWPL)

PURGE(NEWPL,GEOOTHERMAL\$SRC,LC=1,ID=X,PW=X)

RETURN(NEWPL)

REQUEST(LGO,*PF)

RFL(100000)

FTN(I,R=2,B=LGO,OPT=1)

REWIND(LGO)

EDITLIB(USER)

EXTEND(LIB)

RFL(130000)

LDSET(USEP=DATA) -- Used only when BLOCK DATA in GEOCOST is not modified to force it to be loaded from the user library GEOOTHERMAL\$LIB.

LOAD(GEOCOST)

REDUCE.

EXECUTE.

7/8/9

*IDENT: MODIFY

UPDATE Correction Directives and Modified FORTRAN Statements

7/8/9

LIBRARY(LIB,OLD)

REPLACE(*,LGO,AL=1)

FINISH.

ENDRUN.

7/8/9

Input Data Sets

6/7/8/9

- Load the entire set of subroutines required for execution into 130,000 octal words of computer memory.
- Execute the input data sets using the modified program.

The user may wish to prepare a corresponding set of control cards to accomplish the same job processing steps with his/her computer software or else design an alternative sequence of job steps.

5.3 CYBER COMPUTER CONTROL CARDS ILLUSTRATING SEGMENTED LOADING OF GEOCOST

The set of control cards in Table 13 illustrates the segmented loading and execution of GEOCOST, in which the program is partitioned into six main parts called segments. The segmented loading enables different segments of the program to reside in the same area of memory at different times to reduce the memory requirements from 130,000 to 106,000 octal words. The segmentation is based upon the following tree structure, patterned after the hierarchical layout of the subroutines shown in Figures 2 and 3, pages 5 and 6.

- where
- A = Root segment (executive program GEOCOST/HOTROK and associated subroutines), always residing in memory during execution.
 - B = Subroutines LOAD and DSTEAM, together with associated subroutines, to read the input data and control the iterations between the steam power plant and fluid transmission submodels.
 - B1 = Steam power plant submodel, simulated by subroutine STEAM and its associated subroutines.
 - B2 = Fluid transmission and disposal submodel, simulated by subroutine TRANS and its associated subroutines.
 - C = Reservoir economic submodel, simulated by subroutine RESVOR and its associated subroutines.
 - D = Power plant economic submodel, simulated by subroutine PWRPLT and its associated subroutines.

TABLE 13. Control Cards for Segmented Loading and Execution of GEOCOST on the Cyber Computer

Installation Job Card

Installation Account Card

ATTACH(GEOCOST,GEOCOSTSTEAM,ID=X,PW=X)

ATTACH(LIB,GEOTHERMALIB,ID=X,PW=X)

LIBRARY(LIB)

MAP(ON)

RFL(106000)

SEGLOAD.

LOAD(GEOCOST)

REDUCE.

EXECUTE.

RFL(20000)

REWIND(TAPE11)

COPYBF(TAPE11,OUTPUT)

EXIT.

RFL(20000)

REWIND(TAPE11)

COPYBF(TAPE11,OUTPUT)

7/8/9

Used only when case generation mode (ICASE=1) is specified in the input data set.

A INCLUDE GEOCOST,HOTROK,DATA,GCASE,GEVAL,SCASE

A INCLUDE CCSR1,CCSR2,CCSR3,CCBLL,COMALL

A INCLUDE SWITCH,CLEAR,PAGE,FACTRS,CFLASH

A GLOBAL NAMLST,WORK,DATUM,PSEUDO,FLASH,STEAM

A GLOBAL INTRAN,OUTRAN,POINT,FLAGS,STORE,TPRNT

A GLOBAL CONST1,CONST2,CONST3,CONSTL,COMCON

A GLOBAL STM1,STM2,STM3,CURRENT

B INCLUDE LOAD,DSTEAM,FLASH,XPHH,SCRUBR,FLUID,CONVRG

B1 INCLUDE STEAM,GSEJCT,TURBO,SCNDSR,QCC,TOWER

B1 INCLUDE SLOSS,FLUID

B2 INCLUDE TRANS,TROUT,FLPROP,DESIGN,EQCOST,TSTART,PIPE

B2 INCLUDE STORE,SCHEDL,INSUL,SPFLOW,TPFLOW,TPHASE,TPRINT,MOUT

C INCLUDE RESVOR,TARGTS,DATACK,PWRCO,DEPREC,COSTEQ

C INCLUDE PAYOUT,OUTPUT,SUMARY,WRITE

D INCLUDE PWRPLT,PCONST,VAL,DATACK,EXPENSE,DPREC

D INCLUDE COSTEG,PAYOT,OUTPLT,CPOWER

STEAM TREE B-(B1,B2)

GEOCOST TREE A-(STEAM,C,D)

END

7/8/9

Input Data Sets

6/7/8/9

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APPENDIX A

RESERVOIR EXPLORATION, DEVELOPMENT, AND OPERATION COST EQUATIONS

APPENDIX A

RESERVOIR EXPLORATION, DEVELOPMENT, AND OPERATION COST EQUATIONS

The basic equations used in subroutine RESVOR to calculate the costs associated with the exploration, development, and operation of the reservoir are given in this section to aid program users who may wish to change the default input values in Table 6A, page 56. The original list of 39 tasks indexed by N in Table 6B are grouped in three different ways during the calculations in subroutine RESVOR by means of the internal arrays: GROUP(N), ITEX(N), and NTARG(N), $N = 1, \dots, 39$. The array GROUP is used to consolidate the 39 tasks into 31 tasks according to the description of the task. The array ITEX is used to group the tasks according to the time the tasks are scheduled to take place. The array NTARG is used to group the tasks by the major decision points in the reservoir exploration process. Any changes contemplated for these arrays, such as adding tasks or decision points, will require some slight reprogramming in subroutine RESVOR. For this reason, these three arrays are not listed as input arrays.

The cost equations given in this section calculate the total, capitalized, and expensed costs for the tasks in Tables 6A and B without breaking the costs down according to the time in which the tasks occurred. Since the reservoir exploration and development tasks may start in any month during 1 year and end in any month during another year, subroutine RESVOR uses the input time arrays LAGS(ITEX(N), 1) and LAGS(ITEX(N), 2), $ITEX(N) = 1, \dots, 22$, to calculate total, capitalized, and expensed costs for the tasks according to the months in which the tasks are scheduled to occur. This enables the total, capitalized, and expensed costs of the tasks to be accurately totaled on an annual basis in order to calculate annual statements of cash flow, deductible expenses, income, and payout of investments for the reservoir from the beginning of exploration through the economic life of the power plant.

The input array FTF(NTARG(N)-1), $NTARG(N) = 2, \dots, 7$, is used by subroutine RESVOR to calculate the total number of target sites to be

initially identified in order to converge on one site for development and operation after the final decision point.

(Expected number of target sites to identify) * (Fraction of sites retained after decision point I, I = 1, ..., number of decision points) = 1. Substituting FORTRAN variables from subroutine RESVOR and solving this equation,

Expected number of target sites to identify,

$$\text{FAVSIT}(1) = 1/[\text{FTF}(1) * \text{FTF}(2) \dots * \text{FTF}(\text{NUMFTF})].$$

For the default values,

$$\text{FAVSIT}(1) = 1/[1/2 * 1/2 * 2/3 * 3/4 * 1/4 * 1/4] = 128.$$

The number of sites to retain after each decision point is calculated as follows:

Number of sites to retain after decision point J = (Expected number of target sites to identify) * (Fraction of sites retained after decision point I, I = 1, ..., J).

Substituting FORTRAN variables from subroutine RESVOR,

Number of sites to retain after decision point J =

$$\text{FAVSIT}(1) * \text{FTF}(1) * \text{FTF}(2) * \dots * \text{FTF}(J).$$

The array UNIT representing unit costs used in the calculations below is defined at the beginning of subroutine RESVOR as the following function of the input array UNITO (defined in Table 6):

$$\text{UNIT}(N) = \text{RATPR} * \text{UNITO}(N), N = 1, \dots, 22$$

$$\text{UNITO}(n), N = 23, \dots, 39$$

where:

RATPR is defined in subroutine LOAD as the ratio of the input power-plant size (MWe) to the input reservoir size (MWe):

$$\text{RATPR} = \text{DINPUT}(43) / \text{DINPUT}(8), \text{DINPUT}(8) \geq \text{DINPUT}(43).$$

The ratio RATPR is used to scale the input array UNIT0 in order to allocate only the fraction of the costs for the reservoir exploration tasks (N = 1, ..., 22) required to provide enough energy supply for the specified power plant size.

The FORTRAN variables appearing in the following equations taken from subroutine RESVOR are defined as follows:

CSTNEW(IGP) = total dollars required by task IGP

FAVSIT(IGP) = number of favorable sites for task IGP

CAP(IGP) = capitalized dollars for task IGP

EXPENZ(IGP) = expensed dollars for task IGP

where:

IGP = GROUP(N) as defined in Table 6.

Reservoir Exploration Tasks Indexed by N = 1 to 5, N = 9 to 12, N = 15 to 17, and N = 22

$$CSTNEW(IGP) = \sum_{N \text{ in Group IGP}} UNIT(N) * FAVSIT(N)$$

$$CAP(IGP) = \sum_{N \text{ in Group IGP}} UNIT(N)$$

$$EXPENZ(IGP) = CSTNEW(IGP) - CAP(IGP)$$

where:

IGP is defined as GROUP(N) in Table 6.

Lease Procurement, N = 6, 7, 8; IGP = 6

$$CSTNEW(6) = \sum_{N \text{ in Group IGP}} UNIT(N) * ACRES * FAVSIT(N)$$

$$CAP(6) = \sum_{N \text{ in Group IGP}} UNIT(N) * ACRES$$

$$\text{EXPENZ}(6) = \text{CSTNEW}(6) - \text{CAP}(6)$$

where:

ACRES, input through NAMELIST, is the size of each geothermal site leased.

Heat Flow Wells, N = 13, IGP = 10

$$\text{CSTNEW}(10) = \text{UNIT}(13) * 4. * \text{FAVSIT}(10)$$

$$\text{CAP}(10) = \text{UNIT}(13) * 4.$$

$$\text{EXPENZ}(10) = \text{CSTNEW}(10) - \text{CAP}(10)$$

based upon the assumption that 4 wells are drilled per site to measure heat flow.

Temperature Gradient Wells, N = 14, IGP = 11

$$\text{CSTNEW}(11) = \text{UNIT}(14) * 10. * \text{FAVSIT}(11)$$

$$\text{CAP}(11) = \text{UNIT}(14) * 10.$$

$$\text{EXPENZ}(11) = \text{CSTNEW}(11) - \text{CAP}(11)$$

based upon the assumption that 10 wells are drilled per site to measure temperature gradient.

Exploratory Well Drilling, N = 18, 19, 20, 21; IGP = 15

$$\text{RATPR} = \text{DINPUT}(43) / \text{DINPUT}(8)$$

$$\text{CSTNEW}(15) = \text{RATPR} * \text{DCINJW} * \text{FAVSIT}(15)$$

$$\text{CAP}(15) = \text{PERCNT}(1) * \text{CSTNEW}(15) / \text{FAVSIT}(15)$$

$$\text{EXPENZ}(15) = \text{CSTNEW}(15) - \text{CAP}(15)$$

where:

RATPR is the ratio of the input power plant to input reservoir size (MWe). DCINJW, input through NAMELIST, is the cost (dollars) of drilling one exploratory or injection well.

PERCNT(1), input through NAMELIST, is the tangible fraction of the drilling cost.

Production Well Drilling, N = 23, 24; IGP = 17

$CSTNEW(17) = DCPW * WELLS * FAVSIT(17)$

$CAP(17) = PERCNT(1) * CSTNEW(17)$

$EXPENZ(17) = CSTNEW(17) - CAP(17)$

where:

DCPW, input through NAMELIST, is the cost (dollars) of drilling one production well.

WELLS, calculated in subroutine TRANS, is the number of required production wells.

PERCNT(1), input through NAMELIST, is the tangible fraction of the drilling cost.

Nonproduction Well Drilling, N = 25, IGP = 18

$CSTNEW(18) = DCNPW * BADWEL * FAVSIT(18)$

$CAP(18) = 0.$

$EXPENZ(18) = CSTNEW(18)$

where:

DCNPW, input through NAMELIST, is the cost (dollars) of drilling one nonproduction well.

BADWEL, calculated in subroutine TRANS, is the number of nonproduction wells.

Injection Well Drilling, N = 26, 27; IGP = 19

$CSTNEW(19) = DCINJW * WELINJ * FAVSIT(19)$

$CAP(19) = CSTNEW(19)$

$EXPENZ(19) = 0.$

where:

DCINJW, input through NAMELIST, is the cost of drilling one injection well.

WELINJ, calculated in subroutine INJECT, is the total number of injection wells, based upon the flash water effluent and excess water from the cooling tower.

Transmission System, N = 28, IGP = 20

$CSTNEW(20) = UNIT(28) * TCCOST * FAVSIT(20)$

$CAP(20) = CSTNEW(20)$

$EXPENZ(20) = 0.$

where:

TCCOST, calculated in subroutine TRANS, is the capital cost of the fluid transmission system.

Disposal System, N = 29, IGP = 21

$CSTNEW(21) = UNIT(29) * DCCOST * FAVSIT(21)$

$CAP(21) = CSTNEW(21)$

$EXPENZ(21) = 0.$

where:

DCCOST, calculated in subroutine INJECT, is the capital cost of the fluid disposal system

Replacement Wells Based on Production Well Life, N = 30, IGP = 22

$CSTNEW(22) = CSTNEW(17) * UNIT(30) / AVGWL$

$CAP(22) = PERCNT(1) * CSTNEW(22)$

$EXPENZ(22) = CSTNEW(22) - CAP(22)$

where:

CSTNEW(17) is the production well drilling cost.

AVGWL, input through NAMELIST, is the production well life (years).

PERCNT(1), input through NAMELIST, is the tangible fraction of the drilling cost.

Nonproduction Well Drilling Associated with Replacement Wells; N = 31,

IGP = 23

$CSTNEW(23) = FRCNPW * CSTNEW(22)$

$CAP(23) = 0.$

$EXPENZ(23) = 0.$

where:

FRCNPW, input through NAMELIST, is the ratio of nonproduction to production wells drilled.

CSTNEW(22) is the cost of replacement wells drilled.

Well Abandonment, N = 32, IGP = 24

$CSTNEW(24) = UNIT(32) * (WELLS/AVGWL) * FAVSIT(24)$

$CAP(24) = 0.$

$EXPENZ(24) = 0.$

where:

WELLS, calculated in subroutine TRANS, is the number of required production wells.

AVGWL, input through NAMELIST, is the production well life (years).

Well Maintenance, N = 33, IGP = 25

$CSTNEW(25) = UNIT(33) * (WELLS + WELINJ) * FAVSIT(25)$

$CAP(25) = 0.$

$EXPENZ(25) = 0.$

where:

WELLS, calculated in subroutine TRANS, is the number of required production wells.

WELINJ, calculated in subroutine INJECT, is the number of injection wells.

Overhead and Management, N = 34, IGP = 26

CSTNEW(26) = 0.01 * (Total reservoir development cost) +
0.10 * (Total reservoir operation cost excluding
overhead and management)

CAP(26) = 0.

EXPENZ(26) = 0.

Well Redrilling Due to Scale Build-Up in the Production Wells, N = 35, IGP = 27

CSTNEW(27) = UNIT(35) * WELLS * FAVSIT(27)

CAP(27) = 0.

EXPENZ(27) = 0.

where:

WELLS is the number of required production wells.

Annual Injection Well Costs, N = 36, IGP = 28

CSTNEW(28) = UNIT(36) * WELINJ * FAVSIT(28)

CAP(28) = 0.

EXPENZ(28) = 0.

where:

WELINJ, calculated in subroutine INJECT, is the number of injection wells.

Injection Well Maintenance, N = 37, IGP = 29

CSTNEW(29) = UNIT(37) * FAVSIT(29)

CAP(29) = 0.

EXPENZ(29) = 0.

Transmission System Maintenance, N = 38, IGP = 30

CSTNEW(30) = UNIT(38) * TMCOST * FAVSIT(30)

CAP(30) = 0.

EXPENZ(30) = 0.

where:

TMCOST is calculated in subroutine TRANS as TMAINT * TCCOST,

TMAINT, input through NAMELIST, is the transmission maintenance factor (fractional).

TCCOST, calculated in subroutine TRANS, is the capital cost of the fluid transmission system.

Disposal System Maintenance, N = 39, IGP = 31

CSTNEW(31) = UNIT(39) * DMCOST * FAVSIT(31)

CAP(31) = 0.

EXPENZ(31) = 0.

where:

DMCOST is calculated in subroutine INJECT as DMAINT * DCCOST,

DMAINT, input through NAMELIST, is the disposal maintenance factor (fractional).

DCCOST, calculated in subroutine INJECT, is the capital cost of the fluid disposal system.

APPENDIX B

STEAM SEPARATION AND FLASHING DESIGN OPTIONS

APPENDIX B

STEAM SEPARATION AND FLASHING DESIGN OPTIONS

Representative examples of steam separation and flashing of the geothermal fluid are given in this section to illustrate GEOCOST's flexibility in simulating a diverse set of separation and flashing configurations. Steam separation is assumed to occur at the wellhead. Flashing can occur either at the wellhead or at the plant prior to turbine inlet, with a maximum of four stages of flashing. The effluent water from the flashers and excess water from the plant cooling tower are reinjected.

The fluid transmission and disposal submodel can accommodate up to five transmission lines from the reservoir to the power plant and two injection lines. As an example, there could be one transmission line for separated steam prior to any flashing, four transmission lines corresponding to four flash stages at the wellhead, one injection line for reinjecting the effluent water from the fourth flash stage at the wellhead, and one injection line for reinjecting the excess water from the cooling tower at the plant. When flashing occurs at the plant, an injection line from the plant is used in place of the injection line from the reservoir to reinject the effluent water from the plant-located flasher.

An abbreviated set of input values is defined below to set up each configuration. The definitions of the input variables are first reviewed to facilitate understanding of the separation and flashing configurations that follow.

STMFRC Weight fraction of steam in the geothermal fluid at the wellhead.

PRFACT Wellhead overpressurization factor (≥ 1 .) to set the wellhead pressure of the geothermal fluid and the water pressure from wellhead steam separators at saturation or above.

STSEPR Option to separate steam at the wellhead prior to any flashing (0 = separation, 1 = no separation).

NFLASH Number of flash stages.

LFLASH Location of flashers (0 = wellheads, 1 = plant).

MIX Option to mix separated steam and steam from the first flash (0 = no mix, 1 = mix).

LTPHAS Fluid phase allowed in fluid conduction to the power plant (0 = single-phase only, 1 = two-phase allowed).

INJW Option to reinject effluent water from steam separators or flashers at the wellheads (0 = no reinjection, 1 = reinjection).

INJP Option to reinject effluent water from flashers at the plant and excess water from the cooling tower at the plant (0 = no reinjection, 1 = reinjection).

The first six configurations described below require the conduction of steam or two-phase mixtures of steam and water to the power plant. If the pressure of the steam or two-phase mixture entering the transmission pipeline at the wellhead is low, the additional degradation of the pressure during the conduction to the power plant can result in an unacceptably low pressure at the turbine inlet. This will cause an abnormal termination during the iterations between the steam power plant and fluid transmission submodels. In this event, the user should proceed as follows:

- 1) Obtain a full iteration history (LL6=2) of the steam power plant and fluid transmission submodels to analyze the problem.
- 2) Increase EVALUE(2) for pipelines conducting steam or two-phase mixtures of steam and water above its default value of 0.015. Doubling EVALUE(2) is usually a judicious choice, although an additional increase may be necessary. Increasing EVALUE(2) will result in larger internal pipe diameters and less pressure degradation for pipes conducting steam or two-phase mixtures of steam and water.

CONFIGURATION 1 - STEAM SEPARATION AT THE WELLHEAD

Dry steam or separated steam from a steam-water mixture at the wellhead enters the transmission pipeline...fluid conduction to the plant is single-phase only or two-phase allowed...effluent water (if any) from the wellhead steam separator is reinjected...excess water from the cooling tower is reinjected.

$0. < \text{STMFRC} \leq 1.$

MIX = 0

PRFACT = 1.

LTPHAS = 0 or 1 (user's option)

STSEPR = 0

INJW = 1 (0 for all steam)

NFLASH = 0

INJP = 1

LFLASH = 0

If two-phase flow is allowed in steam lines, subroutine DSTEAM removes all steam condensate that forms from two-phase flow prior to power plant inlet. If more than 1% steam condensate occurs, a message is printed cautioning the user that no additional geothermal flow from the wellhead is provided to compensate for the loss of steam by condensation.

CONFIGURATION 2 - FLASHING AT THE WELLHEAD

Single or multiple flashed steam from water or a steam-water mixture at the wellhead enters the transmission pipeline(s)...fluid conduction to the plant is single-phase only or two-phase allowed...effluent water from the wellhead flashers is reinjected...excess water from the cooling tower is reinjected.

$0. \leq \text{STMFRC} < 1.$

MIX = 0

PRFACT = 1.

LTPHAS = 0 or 1 (user's option)

STSEPR = 1

INJW = 1

$1 \leq \text{NFLASH} \leq 4$

INJP = 1

LFLASH = 0

CONFIGURATION 3 - STEAM SEPARATION AND FLASHING AT THE WELLHEAD WITHOUT MIXING

Separated steam from a steam-water mixture and single or multiple flashed steam at the wellhead enter the transmission pipelines separately... fluid conduction to the plant is single-phase only or two-phase allowed... effluent water from the wellhead flashers is reinjected... excess water from the cooling tower is reinjected.

$0. < \text{STMFRC} < 1.$	$\text{MIX} = 0$
$\text{PRFACT} = 1.$	$\text{LTPHAS} = 0 \text{ or } 1 \text{ (user's option)}$
$\text{STSEPR} = 0$	$\text{INJW} = 1$
$1 \leq \text{NFLASH} \leq 4$	$\text{INJP} = 1$
$\text{LFLASH} = 0$	

CONFIGURATION 4 - STEAM SEPARATION AND FLASHING AT THE WELLHEAD WITH MIXING

Separated steam from a steam-water mixture mixed with steam from the first flash in single or multiple flashing at the wellhead and flashed steam enter the transmission pipeline(s)... fluid conduction to the plant is single-phase only or two-phase allowed... effluent water from the wellhead flashers is reinjected... excess water from the cooling tower is reinjected.

$0. < \text{STMFRC} < 1.$	$\text{MIX} = 1$
$\text{PRFACT} = 1.$	$\text{LTPHAS} = 0 \text{ or } 1 \text{ (user's option)}$
$\text{STSEPR} = 0$	$\text{INJW} = 1$
$1 \leq \text{NFLASH} \leq 4$	$\text{INJP} = 1$
$\text{LFLASH} = 0$	

CONFIGURATION 5 - STEAM SEPARATION AT THE WELLHEAD AND FLASHING AT THE PLANT

Separated steam from a steam-water mixture at the wellhead enters the transmission pipeline... fluid conduction to the plant is single-phase only or two-phase allowed... water exiting from the wellhead steam separator is

overpressurized and conducted to the plant in a second pipeline as compressed liquid, where it is flashed to steam using single or multiple flashing prior to power plant inlet...the separated steam from the wellhead and flashed steam at the plant are not mixed prior to turbine inlet...effluent water from the flasher at the plant is reinjected...excess water from the cooling tower is reinjected.

0. < STMFRC < 1.	MIX = 0
PRFACT > 1.	LTPHAS = 0 or 1 (user's option applicable to steam line only in this configuration)
STSEPR = 0	
1 ≤ NFLASH ≤ 4	INJW = 0
LFLASH = 1	INJP = 1

A sufficiently large overpressurization factor (PRFACT) should be initially chosen by the program user to be certain that the pressure of the water exiting from the wellhead steam separators remains above saturation throughout the degradation process in the transmission pipeline to the power plant. A value of 2. for PRFACT is usually a judicious choice. Subroutine DSTEAM minimizes the overpressurization factor by making two passes through the fluid transmission submodel during the first iteration between the steam power plant and fluid transmission submodels. The adjusted overpressurization is the minimum required to conduct the water to the power plant as a compressed liquid without entering into two-phase anywhere along the transmission pipeline. The adjusted overpressurization is actually calculated so that the water arrives at the plant-located flasher at approximately saturation pressure + 10 psia. The value 10 was chosen arbitrarily as a conservative approach to be certain that the pressure of the water remains above saturation (compressed liquid state) throughout the transmission pipeline.

CONFIGURATION 6 - STEAM-WATER MIXTURE AT THE WELLHEAD WITH FLASHING
AT THE PLANT

A steam-water mixture from the wellhead enters the transmission pipeline...fluid conduction to the plant allows two-phase flow...the two-phase fluid is flashed to steam using single or multiple flashing at the plant prior to power plant inlet...effluent water from the flasher at the plant is reinjected...excess water from the cooling tower is reinjected.

$0. < \text{STMFR} < 1.$	$\text{MIX} = 0$
$\text{PRFACT} = 1.$	$\text{LTPHAS} = 1$
$\text{STSEPR} = 1$	$\text{INJW} = 0$
$1 \leq \text{NFLASH} \leq 4$	$\text{INJP} = 1$
$\text{LFLASH} = 1$	

CONFIGURATION 7 - WATER (NO STEAM) AT THE WELLHEAD AND FLASHING AT THE PLANT

Water from the wellhead is overpressurized and enters the transmission pipeline...water conduction to the plant is single-phase only (compressed liquid state)...water is flashed to steam using single or multiple flashing at the plant prior to power plant inlet...effluent water from the flasher at the plant is reinjected...excess water from the cooling tower is reinjected.

$\text{STMFR} = 0.$	$\text{MIX} = 0.$
$\text{PRFACT} > 1.$	$\text{LTPHAS} = 0$
$\text{STSEPR} = 1$	$\text{INJW} = 0.$
$1 \leq \text{NFLASH} \leq 4$	$\text{INJP} = 1$
$\text{LFLASH} = 1$	

APPENDIX C

DIMENSIONAL RESTRICTIONS ON INPUT DATA

APPENDIX C

DIMENSIONAL RESTRICTIONS ON INPUT DATA

The nodal arrays beginning with NODE and ending with EWH in the FORTRAN code for subroutine TRANS, which are used in modeling the fluid conduction and degradation in the fluid transmission submodel, are dimensioned 25 x 25 to accommodate a maximum well field size of 625 wells. Selection of low wellhead temperatures and low flow rates in the input data could result in more than 625 wells. This will cause the program to abnormally terminate and print an error message indicating that the dimensions have been exceeded. Since no dynamic storage is used and no economically viable geothermal plant is likely to require 625 wells, these dimensions could be reduced to 20 x 20 or 15 x 15 if memory size is a problem at the user's computing facilities.

The nodal arrays are currently equivalenced to 9425 decimal locations in the blank common array CCC. A set of economic arrays beginning with CAP and ending with BPSALE, which are used in the reservoir and power plant economic submodels, are equivalenced to the first 6950 decimal locations in the array CCC. The nodal and economic arrays are permitted to share the same locations in blank common to conserve memory, since they are required at different times in the program execution and need not be saved. A reduction in the dimension of the well field to 15 x 15 (225 wells) would permit equivalencing the nodal arrays to the first 3390 decimal locations in the array CCC. The dimension of the CCC array could then be reduced to 6950, the maximum size based upon the economic arrays. The result would be a reduction in memory requirements of 2475 decimal (4653 octal) words. The following changes would also be necessary in the code:

- 1) Reset MD and KD to 15 in subroutine DSTEAM
- 2) Reset NDUP used in subroutine TRANS to 15 in BLOCK DATA
- 3) Change the FORTRAN statement, CALL CLEAR [CCC(1276),MK], to read CALL CLEAR [CCC(466),MK] in subroutine TSTART.

If the user wishes to modify the code in this manner, any questions should be directed to the authors of this manual.

The majority of the reservoir and power plant economic arrays are dimensioned to reflect a maximum operating period of 50 yr. The cumulative effect of a reduction in the maximum time period to 40 yr and the maximum well field size to 15 x 15 would permit reducing the dimension of the blank common array CCC from 9425 to 5560 decimal. This is a reduction of 3865 decimal (7431 octal) words. A change in the dimensions of the economic arrays from the current size of 50 will require careful examination of the reservoir and power plant economic subroutines since some slight changes in the code will be required at various places.

APPENDIX D

LISTING OF SAMPLE CASE OUTPUT

STEAM SEPARATION AND PLANT FLASH

STEAM POWER PLANT SYSTEM AND TRANSMISSION MODEL

SUBROUTINE FLASH

STEAM SEPARATION AND FLASH CONFIGURATION PARAMETERS

GEOHERMAL FLUID STEAM FRACTION .3000
STEAM SEPARATION OPTION AT WELLHEAD YES
NUMBER OF FLASHING STAGES 1
LOCATION OF FLASHERS (PLANT)
STEAM SEPARATION/FLASH MIX OPTION NO

WELLHEAD CONDITIONS

INLET FLUID TEMPERATURE 4.100000E+02 (F)
INLET FLUID PRESSURE 2.766941E+02 (PSIA)
INLET FLUID ENTHALPY 6.308142E+02 (BTU/LB)
CONDENSATE TEMPERATURE 1.260778E+02 (F)
CONDENSATE ENTHALPY 1.116151E+03 (BTU/LB)

NUMBER OF INDIVIDUAL FLOWS TO TURBINE 2

STEAM TEMPERATURE, PRESSURE, ENTHALPY, STEAM FRACTION OF STAGE I
4.100000E+02 2.766941E+02 1.202149E+03 3.000000E-01 SEPARATED
2.680389E+02 4.052709E+01 1.170007E+03 4.221231E-01 FLASHED

SUBROUTINE DSTEAM -- INLET CONDITIONS

GROSS KILOWATT OUTPUT 55000.00
STEAM TEMPERATURE AT TURBINE INLET 393.76 262.98
ABSOLUTE STEAM PRESSURE AT TURBINE INLET 230.1582 37.2558
TURBINE EXHAUST PRESSURE 2.00 (PSIA)
WEIGHT FRACTION OF NONCONDENSIBLE GASES IN STEAM .0033
WET BULB AIR TEMPERATURE 50.00 (F)
DRY BULB AIR TEMPERATURE 70.00 (F)
BAROMETRIC PRESSURE (IN. HG) 29.92
HUMIDITY RATIO .20
COOLING WATER INLET TEMPERATURE 60.00 (F)
INTERCONDENSER EXIT COOLING WATER TEMPERATURE 110.00 (F)
AFTER CONDENSER EXIT COOLING WATER TEMPERATURE 120.00 (F)
MAIN CONDENSER EXIT COOLING WATER TEMPERATURE 119.08 (F)
OIL COOLER EXIT COOLING WATER TEMPERATURE 120.00 (F)
HYDROGEN COOLER EXIT COOLING WATER TEMPERATURE 120.00 (F)
WELLHEAD PRESSURE AT SATURATION 276.69 (PSIA)
PER CENT OF DISSOLVED SOLIDS IN STEAM 3.00
WATER OVERPRESSURIZATION FACTOR 2.00
CONDENSER INLET TEMPERATURE 126.08 (F)

SUBROUTINE GSEJCT -- GAS EXTRACTION

SATURATION TEMPERATURE OF FIRST STAGE 1.260778E+02 (F)
SATURATION PRESSURE OF FIRST STAGE 1.516700E+00 (PSIA)
WAV - GAS/STEAM RATIO OF FIRST STAGE 5.098980E-01 (LB GAS/LB STEAM)
SATURATION TEMPERATURE OF SECOND STAGE 1.622383E+02 (F)
SATURATION PRESSURE OF SECOND STAGE 3.929493E+00 (PSIA)
WAV - GAS/STEAM RATIO OF SECOND STAGE 4.345859E-01 (LB GAS/LB STEAM)

SUBROUTINE TURBO -- STEAM TURBINE

NUMBER OF INDIVIDUAL FLOWS TO TURBINE
 PRESSURE AT TURBINE INLET
 ENTHALPY OF STEAM AT TURBINE INLET
 ACTUAL STEAM RATE
 THEORETICAL STEAM RATE
 ACTUAL HEAT RATE
 INDIVIDUAL STEAM FLOW

2
 2.301582E+02 3.725580E+01
 1.206136E+03 1.168367E+03
 1.499184E+01 2.429539E+01
 1.100105E+01 1.782802E+01
 1.799225E+04 2.838592E+04
 6.686718E+05 2.526142E+05

SUBROUTINE STEAM -- COOLING WATER REQUIREMENTS

INTERCONDENSER FLOW
 AFTERCONDENSER FLOW
 TURBINE OIL COOLER
 HYDROGEN GENERATOR COOLER
 CONDENSER FLOW
 TEMPERATURE OF COOLING WATER INTO TOWER

1.523485E+05 (LB/HR)
 1.313218E+05 (LB/HR)
 2.343447E+04 (LB/HR)
 8.905100E+04 (LB/HR)
 2.118040E+07 (LB/HR)
 1.190263E+02 (F)

SUBROUTINE TOWER -- COOLING TOWER

COOLING TOWER AIR FLOW RATE (LB/HR)
 COOLING TOWER EVAPORATION RATE (LB/HR)
 WET BULB AIR TEMPERATURE (F)
 DRY BULB AIR TEMPERATURE (F)
 BAROMETRIC PRESSURE (IN. HG)
 HUMIDITY RATIO
 HEAT LOAD (BTU/HR)

4.756273E+06
 7.106092E+05
 5.000000E+01
 7.000000E+01
 2.992000E+01
 2.000000E-01
 8.692632E+08

SUBROUTINE SLOSS -- INTERNAL POWER REQUIREMENTS

KW REQUIRED FOR FANS
 CONDENSATE PUMPS TO COOLING TOWER
 COOLING WATER PUMPS
 COOLING TOWER REINJECTION PUMP
 FLASH REINJECTION PUMPS
 VACUUM PUMP ON CONDENSER
 SCRUBBER PUMP
 WATER PRESSURIZING BOOSTER PUMPS

6.902679E+02 (KW) PER CENT OF GRKW 1.255033E+00
 4.484689E+02 (KW) PER CENT OF GRKW 8.153980E-01
 8.814443E+02 (KW) PER CENT OF GRKW 1.602626E+00
 1.205486E+01 (KW) PER CENT OF GRKW 2.191792E-02
 7.240351E+01 (KW) PER CENT OF GRKW 1.316427E-01
 0. (KW) PER CENT OF GRKW 0.
 1.086005E+00 (KW) PER CENT OF GRKW 1.974554E-03
 2.231151E+01 (KW) PER CENT OF GRKW 4.056638E-02

SUBROUTINE STEAM -- OVERALL RESULTS

ACTUAL GROSS STEAM RATE (LBS/KWHR)
 ACTUAL GROSS HEAT RATE (BTU/KWHR)
 ACTUAL NET STEAM RATE (LBS/KWHR)
 ACTUAL NET HEAT RATE (BTU/KWHR)
 AVERAGE NET STEAM RATE (LBS/KWHR)
 AVERAGE NET HEAT RATE (BTU/KWHR)
 STEAM FLOW TO TURBINE (LBS/HR)
 TOTAL STEAM FLOW (LBS/HR)
 TOTAL WELHEAD FLOW (LBS/HR)
 TOTAL COOLING WATER REQUIREMENTS (LBS/HR)
 COOLING TOWER AIR FLOW RATE (CFM)
 COOLING TOWER EVAPORATION RATE (LBS/HR)
 REINJECTION RATE-BLOWDOWN (LBS/HR)
 FLASH REINJECTION RATE (LBS/HR)
 KW LOSSES FOR EQUIPMENT
 NET KILOWATT OUTPUT (KW)

1.499184E+01 2.429539E+01
 1.799225E+04 2.838592E+04
 1.579002E+01 2.558889E+01
 1.898195E+04 2.993591E+04
 1.847684E+01
 2.198549E+04
 9.212860E+05
 9.327921E+05
 2.267260E+06
 2.157656E+07
 4.756273E+06
 7.106092E+05
 2.221828E+05
 1.334468E+06
 2.128037E+03
 5.287196E+04

INPUT CONDITIONS -- TRANSMISSION MODEL

GEOHERMAL PLANT TYPE	STEAM	
GEOPRESSURE OPTION	0	
WELLHEAD TEMPERATURE (F)	4.100000E+02	
WELLHEAD PRESSURE AT SATURATION (PSIA)	2.766941E+02	
WELLHEAD STEAM FRACTION	3.000000E-01	
WELLHEAD FLUID STATE	TWO PHASE	
WATER OVERPRESSURIZATION FACTOR	2.000000E+00	
ADJUSTED OVERPRESSURIZATION FACTOR	1.081350E+00	
MAXIMUM FLOW RATE/WELL (LB/SEC)	9.722222E+01	
STEAM SEPERATION AT WELLHEAD	0	
NUMBER OF FLASHING STAGES	1	
LOCATION OF FLASHERS	PLANT	
STEAM SEPARATION/FLASH MIX OPTION	0	
WELL SPACING (ACRES)	2.000000E+01	
FRACTION EXCESS PRODUCING WELLS	2.000000E-01	
FRACTION NONPRODUCING WELLS	2.000000E-01	
WELL LIFE (YRS)	1.000000E+01	
MAXIMUM ROWS IN WELL DESIGN MATRIX	25	
MAXIMUM COLUMNS IN WELL DESIGN MATRIX	25	
TRANSMISSION MAINTENANCE FACTOR	5.000000E-02	
DISPOSAL MAINTENANCE FACTOR	5.000000E-02	
FRACTION OF PIPE THAT CAN BE SALVAGED	1.000000E-01	
TRANSMISSION TWO-PHASE FLOW OPTION	1	
PLANT AVAILABILITY (HRS/YR)	7.452120E+03	
TOTAL FLOW RATE REQUIRED BY PLANT (LB/HR)	2.267260E+06	
OPTIONAL INJECTION WELLS USING WELL EFFLUENT	0	
DISTANCE FROM WELL FIELD TO INJECTION WELLS (MI)	1.000000E+03	
OPTIONAL INJECTION WELLS USING PLANT EFFLUENT	1	
DISTANCE FROM PLANT TO INJECTION WELLS (MI)	1.000000E+03	
RATIO OF INJECTION/PRODUCTION WELL FLOW RATE	2.000000E+00	
REINJECTION PUMPING OPTION	1	
LABOR COST FOR PIPE INSULATION (\$/FT)	4.500000E+00	
OPTION TO REDUCE NODAL RECOMPUTATION	1	
VALUE OF OUTPUT ELECTRIC ENERGY (EVALUES)	2.000000E-02	1.500000E-02
ANNUALIZED COST FACTOR	1.365263E-01	
NET HEAT RATE FOR TRANSMISSION LINE(S) (KWT/KWE)	5.188135E+00	1.439937E+01

N O D A L F L U I D T R A N S M I S S I O N T H E R M O D Y N A M I C D E G R A D A T I O N F O R L I N E 1														
NODE		STEAM			FLOW RATE	HEAT LOSS	SATURATION			ENTHALPY	PIPE INTER	EXTER	INSUL	
I	J	ITR	MIX FLUID STATE	FRACT	(LB/SEC)	(BTU/SEC-FT)	TEMP (F)	PRES(PSIA)	PRES(PSIA)	(BTU/LB)	SCHD	DIAM(IN)	DIAM(IN)	THK(IN)
4	2	1	SAT VAPOR	1.0000	24.	0.000	410.000	276.694	276.694	1202.149	10.	9.754	10	5.000
4	2	2	TWO PHASE	.9994	24.	.028	407.596	269.381	269.381	1200.831	10.	9.793	10	5.000
4	2	3	TWO PHASE	.9987	24.	.028	407.644	269.527	269.527	1200.831	10.	9.793	10	5.000
4	1	1	TWO PHASE	.9987	24.	0.000	407.644	269.527	269.527	1200.831	10.	9.831	10	5.000
4	1	2	TWO PHASE	.9981	24.	.028	405.227	262.323	262.323	1199.524	10.	9.871	10	5.000
4	1	3	TWO PHASE	.9975	24.	.028	405.275	262.465	262.465	1199.524	10.	9.871	10	5.000
3	3	0	TWO PHASE	.9987	24.	.028	407.644	269.527	269.527	1200.831	10.	9.793	10	5.000
3	2	1	M TWO PHASE	.9995	47.	0.000	407.644	269.527	269.527	1201.490	10.	13.554	14	5.000
3	2	2	TWO PHASE	.9991	47.	.037	405.820	264.078	264.078	1200.635	10.	13.596	14	5.000
3	2	3	TWO PHASE	.9987	47.	.037	405.848	264.159	264.159	1200.635	10.	13.596	14	5.000
3	1	1	M TWO PHASE	.9984	71.	0.000	405.275	262.465	262.465	1200.265	10.	16.485	18	5.000
3	1	2	TWO PHASE	.9990	71.	.044	403.716	257.898	257.898	1199.575	10.	16.529	18	5.000
3	1	3	TWO PHASE	.9977	71.	.044	403.736	257.957	257.957	1199.575	10.	16.529	18	5.000
2	3	0	TWO PHASE	.9987	24.	.028	407.644	269.527	269.527	1200.831	10.	9.793	10	5.000
2	2	0	M TWO PHASE	.9987	47.	.037	405.848	264.159	264.159	1200.635	10.	13.596	14	5.000
2	1	1	M TWO PHASE	.9983	118.	0.000	403.736	257.957	257.957	1199.999	10.	20.997	22	5.000
2	1	2	TWO PHASE	.9981	118.	.052	402.461	254.265	254.265	1199.516	10.	21.043	22	5.000
2	1	3	TWO PHASE	.9979	118.	.052	402.474	254.305	254.305	1199.516	10.	21.043	22	5.000
1	4	0	TWO PHASE	.9987	24.	.028	407.644	269.527	269.527	1200.831	10.	9.793	10	5.000
1	3	0	M TWO PHASE	.9987	47.	.037	405.848	264.159	264.159	1200.635	10.	13.596	14	5.000
1	2	1	M TWO PHASE	.9993	71.	0.000	405.848	264.159	264.159	1201.140	10.	16.456	18	5.000
1	2	2	TWO PHASE	.9990	71.	.044	404.292	259.577	259.577	1200.448	10.	16.500	18	5.000
1	2	3	TWO PHASE	.9987	71.	.044	404.312	259.636	259.636	1200.448	10.	16.500	18	5.000
1	1	1	M TWO PHASE	.9983	189.	0.000	402.474	254.305	254.305	1199.866	10.	26.218	28	6.000
1	1	2	TWO PHASE	.9982	189.	.054	401.413	251.265	251.265	1199.551	10.	26.267	28	6.000
1	1	3	TWO PHASE	.9981	189.	.054	401.423	251.292	251.292	1199.551	10.	26.267	28	6.000

TRANSMISSION DESIGN, THERMODYNAMICS, AND COST

LINE NUMBER 1 (STEAM)

INLET TEMPERATURE INTO LINE	4.100000E+02	(F)
INLET PRESSURE INTO LINE	2.766941E+02	(PSIA)
INLET ENTHALPY INTO LINE	1.202149E+03	(BTU/LB)
NUMBER OF TRANSMISSION LINES INTO PLANT	2	(LINES)
NUMBER OF PRODUCING WELLS	8	(WELLS)
NUMBER OF DRY WELLS	2	(WELLS)
ACTUAL WELL FLOW RATE	2.361729E+01	(LBH/SEC)
EFFECTIVE WELL SPACING	2.400000E+01	(ACRES)
PIPE LENGTH BETWEEN NODES	3.348875E+02	(METERS)

WELL FIELD DESIGN LATTICE WITH ACTIVE WELLS NUMBERED

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

0	1	3	6
0	2	5	0
0	4	8	0
0	7	0	0

NUMBER OF UPSTREAM WELLS FLOWING INTO EACH NODE

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

8	3	2	1
5	2	1	0
3	2	1	0
1	1	0	0

INITIAL WELL HEAD CONDITIONS

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	4.100000E+02	4.100000E+02	4.100000E+02
ROW 2	0.	4.100000E+02	4.100000E+02	0.
ROW 3	0.	4.100000E+02	4.100000E+02	0.
ROW 4	0.	4.100000E+02	0.	0.

PRESSURE (PSIA)

	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	2.766941E+02	2.766941E+02	2.766941E+02
ROW 2	0.	2.766941E+02	2.766941E+02	0.
ROW 3	0.	2.766941E+02	2.766941E+02	0.
ROW 4	0.	2.766941E+02	0.	0.

VISCOSITY (LB/FT-SEC)

	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	1.101115E-05	1.101115E-05	1.101115E-05
ROW 2	0.	1.101115E-05	1.101115E-05	0.
ROW 3	0.	1.101115E-05	1.101115E-05	0.
ROW 4	0.	1.101115E-05	0.	0.

DENSITY (LB/CU FT)

	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	5.988944E-01	5.988944E-01	5.988944E-01
ROW 2	0.	5.988944E-01	5.988944E-01	0.
ROW 3	0.	5.988944E-01	5.988944E-01	0.
ROW 4	0.	5.988944E-01	0.	0.

NODAL EXIT CONDITIONS AFTER DEGRADATION AND MIXING

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

	COL 1	COL 2	COL 3	COL 4
ROW 1	4.024745E+02	4.058477E+02	4.076441E+02	4.100000E+02
ROW 2	4.037362E+02	4.076441E+02	4.100000E+02	0.
ROW 3	4.052748E+02	4.076441E+02	4.100000E+02	0.
ROW 4	4.076441E+02	4.100000E+02	0.	0.

PRESSURE (PSIA)

	COL 1	COL 2	COL 3	COL 4
ROW 1	2.543046E+02	2.641592E+02	2.695267E+02	2.766941E+02
ROW 2	2.579565E+02	2.695267E+02	2.766941E+02	0.
ROW 3	2.624650E+02	2.695267E+02	2.766941E+02	0.
ROW 4	2.695267E+02	2.766941E+02	0.	0.

VISCOSITY (LB/FT-SEC)

	COL 1	COL 2	COL 3	COL 4
ROW 1	1.091289E-05	1.095431E-05	1.097987E-05	1.101115E-05
ROW 2	1.093213E-05	1.097987E-05	1.101115E-05	0.
ROW 3	1.095445E-05	1.097987E-05	1.101115E-05	0.
ROW 4	1.098704E-05	1.101115E-05	0.	0.

DENSITY (LB/CU FT)

	COL 1	COL 2	COL 3	COL 4
ROW 1	5.525632E-01	5.727955E-01	5.840348E-01	5.988944E-01
ROW 2	5.602961E-01	5.840348E-01	5.988944E-01	0.
ROW 3	5.697718E-01	5.840348E-01	5.988944E-01	0.
ROW 4	5.845005E-01	5.988944E-01	0.	0.

INTERNAL PIPE DIAMETER (IN)

	COL 1	COL 2	COL 3	COL 4
ROW 1	2.626685E+01	1.649992E+01	1.359611E+01	9.792898E+00
ROW 2	2.104279E+01	1.359611E+01	9.792898E+00	0.
ROW 3	1.652857E+01	1.359611E+01	9.792898E+00	0.
ROW 4	9.870780E+00	9.792898E+00	0.	0.

PIPE INSULATION THICKNESS (IN)

	COL 1	COL 2	COL 3	COL 4
ROW 1	6.000000E+00	5.000000E+00	5.000000E+00	5.000000E+00
ROW 2	5.000000E+00	5.000000E+00	5.000000E+00	0.
ROW 3	5.000000E+00	5.000000E+00	5.000000E+00	0.
ROW 4	5.000000E+00	5.000000E+00	0.	0.

PLANT INLET CONDITIONS (INCLUDES DEGRADATION FROM LAST NODE TO PLANT)

FLOW RATE 6.80177E+05 (LBM/HR) BEFORE SEPARATION OF STEAM CONDENSATE FROM TWO-PHASE FLOW

FLOW RATE 6.788583E+05 (LBM/HR) AFTER SEPARATION OF STEAM CONDENSATE FROM TWO-PHASE FLOW

SATURATED VAPOR CONDITION IS USED TO CALCULATE ENTHALPY
IF ANY STEAM CONDENSATE IS SEPARATED FROM TWO-PHASE FLOW

TEMPERATURE 4.014229E+02 (F)
PRESSURE 2.512919E+02 (PSIA)
ENTHALPY 1.201151E+03 (BTU/LB)

TRANSMISSION SYSTEM COSTS (\$)

TOTAL TRANSMISSION COST 1.729896E+06
PIPE COST 9.004325E+05
INSULATION COST 2.223388E+05
WELLHEAD VALVES 4.000000E+04
PRESSURE INSTRUMENTS 1.600000E+04
ROCK SEPARATORS 4.000000E+04
CYCLONE SEPARATOR 3.500000E+04
MUFFLING DRAG VALVES 0.
WELLHEAD FLASHERS 0.
WELLHEAD STEAM SEPARATORS 4.761245E+05
TRANSMISSION BOOSTER PUMPS 0.
TRANSMISSION MAINTENANCE COST 8.649479E+04
TRANSMISSION CAPITAL REPLACEMENT 9.000000E+02 (RATE)

MODAL FLUID TRANSMISSION THERMODYNAMIC DEGRADATION FOR LINE 2																			
NODE		I	J	ITR	MIX	FLUID	STATE	STEAM FRACT	FLOW RATE (LB/SEC)	HEAT LOSS (BTU/SEC-FT)	TEMP (F)	PRES (PSIA)	SATURATION		ENTHALPY (BTU/LB)	PIPE SCHED	INTER DIAM (IN)	EXTER DIAM (IN)	INSUL THK (IN)
													PRES (PSIA)	ENTHALPY (BTU/LB)					
4	2	1				COMPRESSED	0.0000		55.	0.000	410.000	299.203	276.694	385.980	10.	6.341	8	5.000	
4	2	2				COMPRESSED	0.0000		55.	.024	409.568	294.851	275.368	385.505	10.	6.341	8	5.000	
4	2	3				COMPRESSED	0.0000		55.	.024	409.568	294.850	275.368	385.505	10.	6.341	8	5.000	
4	1	1				COMPRESSED	0.0000		55.	0.000	409.568	294.850	275.368	385.505	10.	6.341	8	5.000	
4	1	2				COMPRESSED	0.0000		55.	.024	409.136	290.497	274.048	385.031	10.	6.341	8	5.000	
4	1	3				COMPRESSED	0.0000		55.	.024	409.136	290.496	274.048	385.031	10.	6.341	8	5.000	
3	3	0				COMPRESSED	0.0000		55.	.024	409.568	294.850	275.368	385.505	10.	6.341	8	5.000	
3	2	1	M			COMPRESSED	0.0000		110.	0.000	409.786	294.850	276.038	385.742	10.	8.766	10	5.000	
3	2	2				COMPRESSED	0.0000		110.	.028	409.529	291.599	275.248	385.459	10.	8.765	10	5.000	
3	2	3				COMPRESSED	0.0000		110.	.028	409.529	291.598	275.248	385.459	10.	8.765	10	5.000	
3	1	1	M			COMPRESSED	0.0000		165.	0.000	409.398	290.496	274.850	385.316	10.	10.594	12	5.000	
3	1	2				COMPRESSED	0.0000		165.	.033	409.200	287.756	274.245	385.098	10.	10.594	12	5.000	
3	1	3				COMPRESSED	0.0000		165.	.033	409.200	287.755	274.245	385.098	10.	10.594	12	5.000	
2	3	0				COMPRESSED	0.0000		55.	.024	409.568	294.850	275.368	385.505	10.	6.341	8	5.000	
2	2	0	M			COMPRESSED	0.0000		110.	.028	409.529	291.598	275.248	385.459	10.	8.765	10	5.000	
2	1	1	M			COMPRESSED	0.0000		276.	0.000	409.333	287.755	274.650	385.243	10.	13.453	14	5.000	
2	1	2				COMPRESSED	0.0000		276.	.037	409.199	285.549	274.241	385.095	10.	13.453	14	5.000	
2	1	3				COMPRESSED	0.0000		276.	.037	409.199	285.549	274.241	385.095	10.	13.453	14	5.000	
1	4	0				COMPRESSED	0.0000		55.	.024	409.568	294.850	275.368	385.505	10.	6.341	8	5.000	
1	3	0	M			COMPRESSED	0.0000		110.	.028	409.529	291.598	275.248	385.459	10.	8.765	10	5.000	
1	2	1	M			COMPRESSED	0.0000		165.	0.000	409.688	291.598	275.737	385.633	10.	10.595	12	5.000	
1	2	2				COMPRESSED	0.0000		165.	.033	409.490	288.859	275.130	385.414	10.	10.595	12	5.000	
1	2	3				COMPRESSED	0.0000		165.	.033	409.490	288.858	275.130	385.414	10.	10.595	12	5.000	
1	1	1	M			COMPRESSED	0.0000		441.	0.000	409.309	285.549	274.578	385.215	10.	16.764	18	5.000	
1	1	2				COMPRESSED	0.0000		441.	.045	409.207	283.742	274.266	385.102	10.	16.763	18	5.000	
1	1	3				COMPRESSED	0.0000		441.	.045	409.207	283.741	274.266	385.102	10.	16.763	18	5.000	

TRANSMISSION DESIGN, THERMODYNAMICS, AND COST

LINE NUMBER 2 (WATER)

INLET TEMPERATURE INTO LINE	4.100000E+02	(F)
INLET PRESSURE INTO LINE	2.992033E+02	(PSIA)
INLET ENTHALPY INTO LINE	3.859796E+02	(BTU/LB)
NUMBER OF TRANSMISSION LINES INTO PLANT	2	(LINES)
NUMBER OF PRODUCING WELLS	8	(WELLS)
NUMBER OF DRY WELLS	2	(WELLS)
ACTUAL WELL FLOW RATE	5.510701E+01	(LBM/SEC)
EFFECTIVE WELL SPACING	2.400000E+01	(ACRES)
PIPE LENGTH BETWEEN NODES	3.348875E+02	(METERS)

WELLFIELD DESIGN LATTICE WITH ACTIVE WELLS NUMBERED

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

0	1	3	6
0	2	5	0
0	4	8	0
0	7	0	0

NUMBER OF UPSTREAM WELLS FLOWING INTO EACH NODE

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

8	3	2	1
5	2	1	0
3	2	1	0
1	1	0	0

INITIAL WELLHEAD CONDITIONS

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

ROW	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	4.100000E+02	4.100000E+02	4.100000E+02
ROW 2	0.	4.100000E+02	4.100000E+02	0.
ROW 3	0.	4.100000E+02	4.100000E+02	0.
ROW 4	0.	4.100000E+02	0.	0.

PRESSURE (PSIA)

ROW	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	2.992033E+02	2.992033E+02	2.992033E+02
ROW 2	0.	2.992033E+02	2.992033E+02	0.
ROW 3	0.	2.992033E+02	2.992033E+02	0.
ROW 4	0.	2.992033E+02	0.	0.

VISCOSITY (LB/FT-SEC)

ROW	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	8.557482E-05	8.557482E-05	8.557482E-05
ROW 2	0.	8.557482E-05	8.557482E-05	0.
ROW 3	0.	8.557482E-05	8.557482E-05	0.
ROW 4	0.	8.557482E-05	0.	0.

DENSITY (LB/CU FT)

	COL 1	COL 2	COL 3	COL 4
ROW 1	0.	5.324685E+01	5.324685E+01	5.324685E+01
ROW 2	0.	5.324685E+01	5.324685E+01	0.
ROW 3	0.	5.324685E+01	5.324685E+01	0.
ROW 4	0.	5.324685E+01	0.	0.

NODAL EXIT CONDITIONS AFTER DEGRADATION AND MIXING

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

	COL 1	COL 2	COL 3	COL 4
ROW 1	4.093093E+02	4.096883E+02	4.097862E+02	4.100000E+02
ROW 2	4.093330E+02	4.097862E+02	4.100000E+02	0.
ROW 3	4.093983E+02	4.097862E+02	4.100000E+02	0.
ROW 4	4.095678E+02	4.100000E+02	0.	0.

PRESSURE (PSIA)

	COL 1	COL 2	COL 3	COL 4
ROW 1	2.855486E+02	2.915982E+02	2.948501E+02	2.992033E+02
ROW 2	2.877555E+02	2.948501E+02	2.992033E+02	0.
ROW 3	2.904958E+02	2.948501E+02	2.992033E+02	0.
ROW 4	2.948501E+02	2.992033E+02	0.	0.

VISCOSITY (LB/FT-SEC)

	COL 1	COL 2	COL 3	COL 4
ROW 1	8.572151E-05	8.563935E-05	8.562001E-05	8.557482E-05
ROW 2	8.571838E-05	8.562001E-05	8.557482E-05	0.
ROW 3	8.570608E-05	8.562001E-05	8.557482E-05	0.
ROW 4	8.567115E-05	8.557482E-05	0.	0.

DENSITY (LB/CU FT)

	COL 1	COL 2	COL 3	COL 4
ROW 1	5.327177E+01	5.325758E+01	5.325452E+01	5.324685E+01
ROW 2	5.327154E+01	5.325452E+01	5.324685E+01	0.
ROW 3	5.326970E+01	5.325452E+01	5.324685E+01	0.
ROW 4	5.326395E+01	5.324685E+01	0.	0.

INTERNAL PIPE DIAMETER (IN)

	COL 1	COL 2	COL 3	COL 4
ROW 1	1.676341E+01	1.059461E+01	8.765412E+00	6.341018E+00
ROW 2	1.345323E+01	8.765412E+00	6.341018E+00	0.
ROW 3	1.059403E+01	8.765412E+00	6.341018E+00	0.
ROW 4	6.340537E+00	6.341018E+00	0.	0.

PIPE INSULATION THICKNESS (IN)

	COL 1	COL 2	COL 3	COL 4
ROW 1	5.000000E+00	5.000000E+00	5.000000E+00	5.000000E+00
ROW 2	5.000000E+00	5.000000E+00	5.000000E+00	0.
ROW 3	5.000000E+00	5.000000E+00	5.000000E+00	0.
ROW 4	5.000000E+00	5.000000E+00	0.	0.

PLANT INLET CONDITIONS (INCLUDES DEGRADATION FROM LAST NODE TO PLANT)

FLOW RATE 1.587082E+06 (LBH/HR)

TEMPERATURE 4.092072E+02 (F)

PRESSURE 2.837415E+02 (PSIA)

ENTHALPY 3.851018E+02 (BTU/LB)

TRANSMISSION SYSTEM COSTS (\$)

TOTAL TRANSMISSION COST 2.478497E+06
PIPE COST 1.442076E+06
INSULATION COST 4.108915E+05
WELLHEAD VALVES 4.000000E+04
PRESSURE INSTRUMENTS 1.600000E+04
ROCK SEPARATORS 4.000000E+04
CYCLONE SEPARATOR 3.500000E+04
MUFFLING DRAG VALVES 0.
WELLHEAD FLASHERS 0.
WELLHEAD STEAM SEPARATORS 4.761245E+05
TRANSMISSION BOOSTER PUMPS 1.840506E+04
TRANSMISSION MAINTENANCE COST 1.239248E+05
TRANSMISSION CAPITAL REPLACEMENT 9.000000E-02 (RATE)

SUBROUTINE FLASH

STEAM SEPARATION AND FLASH CONFIGURATION PARAMETERS

GEOHERMAL FLUID STEAM FRACTION 0.0000
STEAM SEPARATION OPTION AT WELLHEAD YES
NUMBER OF FLASHING STAGES 1
LOCATION OF FLASHERS (PLANT)
STEAM SEPARATION/FLASH MIX OPTION NO

PLANT CONDITIONS

INLET FLUID TEMPERATURE 4.092072E+02 (F)
INLET FLUID PRESSURE 2.837415E+02 (PSIA)
INLET FLUID ENTHALPY 3.851023E+02 (BTU/LB)
CONDENSATE TEMPERATURE 1.260778E+02 (F)
CONDENSATE ENTHALPY 1.116151E+03 (BTU/LB)

NUMBER OF INDIVIDUAL FLOWS TO TURBINE 1

STEAM TEMPERATURE, PRESSURE, ENTHALPY, STEAM FRACTION OF STAGE 1
2.676425E+02 4.026243E+01 1.169879E+03 1.591690E-01 FLASHED

STEAM SCRUBBER MODEL
(BASED UPON STEAM FLOW RATES DEMANDED BY PLANT)

STEAM LINE 1 TO TURBINE ... SCRUBBER PARAMETERS
TOTAL STEAM FLOW TO SCRUBBER 6.801779E+05 (LB/HR)
STEAM TEMPERATURE AT SCRUBBER INLET 4.014229E+02 (F)
STEAM PRESSURE AT SCRUBBER INLET 2.512919E+02 (PSIA)
STEAM ENTHALPY AT SCRUBBER INLET 1.201151E+03 (BTU/LB)
STEAM TEMPERATURE AT SCRUBBER EXIT 3.937566E+02 (F)
STEAM PRESSURE AT SCRUBBER EXIT 2.301579E+02 (PSIA)
STEAM ENTHALPY AT SCRUBBER EXIT 1.200136E+03 (BTU/LB)
TEMPERATURE AT DEMINERALIZER INPUT 1.190778E+02 (F)
TEMPERATURE AT ENTRANCE TO SCRUBBER 2.531249E+02 (F)
TEMPERATURE AT HOT STREAM HEATER INLET 3.937566E+02 (F)
TEMPERATURE AT HOT STREAM HEATER EXIT 2.631249E+02 (F)

HEAT EXCHANGER DESIGN

INSIDE TUBE DIAMETER 4.166000E-02 (FT)
NUMBER OF TUBES IN UNIT 9.000000E+00
INSIDE TUBE HEAT TRANSFER COEFFICIENT 3.470924E+03 (BTU/HR SQ FT F)
OUTSIDE TUBE HEAT TRANSFER COEFFICIENT 4.157275E+03 (BTU/HR SQ FT F)
HEAT TRANSFER LENGTH 3.657292E+01 (FT)
OVERALL HEAT TRANSFER COEFFICIENT 3.578479E+02 (BTU/HR SQ FT F)

QUANTITY OF WATER TO SCRUB STEAM 2.040534E+04 (LB/HR)

STEAM LINE 2 TO TURBINE ... SCRUBBER PARAMETERS
TOTAL STEAM FLOW TO SCRUBBER 2.526142E+05 (LB/HR)
STEAM TEMPERATURE AT SCRUBBER INLET 2.676425E+02 (F)
STEAM PRESSURE AT SCRUBBER INLET 4.026243E+01 (PSIA)
STEAM ENTHALPY AT SCRUBBER INLET 1.169879E+03 (BTU/LB)
STEAM TEMPERATURE AT SCRUBBER EXIT 2.629839E+02 (F)
STEAM PRESSURE AT SCRUBBER EXIT 3.725580E+01 (PSIA)
STEAM ENTHALPY AT SCRUBBER EXIT 1.161367E+03 (BTU/LB)
TEMPERATURE AT DEMINERALIZER INPUT 1.190778E+02 (F)
TEMPERATURE AT ENTRANCE TO SCRUBBER 1.861445E+02 (F)
TEMPERATURE AT HOT STREAM HEATER INLET 2.629839E+02 (F)
TEMPERATURE AT HOT STREAM HEATER EXIT 1.961445E+02 (F)

HEAT EXCHANGER DESIGN

INSIDE TUBE DIAMETER 4.166000E-02 (FT)
NUMBER OF TUBES IN UNIT 3.000000E+00
INSIDE TUBE HEAT TRANSFER COEFFICIENT 2.568515E+03 (BTU/HR SQ FT F)
OUTSIDE TUBE HEAT TRANSFER COEFFICIENT 4.169771E+03 (BTU/HR SQ FT F)
HEAT TRANSFER LENGTH 3.938359E+01 (FT)
OVERALL HEAT TRANSFER COEFFICIENT 3.424303E+02 (BTU/HR SQ FT F)

QUANTITY OF WATER TO SCRUB STEAM 7.578425E+03 (LB/HR)

POWERPLANT - FLUID TRANSMISSION CONVERGENCE TEST

PREVIOUS GEOTHERMAL FLOW RATE DEMANDED BY PLANT (LBM/HR)	2.267209E+06
CURRENT GEOTHERMAL FLOW RATE DEMANDED BY PLANT (LBM/HR)	2.267260E+06
DIFFERENCE (LBM/HR)	5.046040E+01
DIFFERENCE (PER CENT)	2.225612E-03
CONVERGENCE CRITERION (PER CENT)	2.000000E+00

POWERPLANT AND FLUID TRANSMISSION MODELS SATISFY CONVERGENCE CRITERION

STEAM CONDENSATE LOSSES IN STEAM LINES FROM TWO-PHASE FLOW (LBM/HR OF STEAM)	1.319554E+03
STEAM FLOW RATE DEMANDED BY PLANT (LBM/HR OF STEAM)	9.327921E+05
PER CENT STEAM CONDENSATE LOSSES FROM TWO-PHASE FLOW	1.414628E-01
DISPOSAL/INJECTION PIPING ANNUALIZED COST FACTOR	1.365263E-01

PIPE FROM PLANT TO INJECTION FIELD (EXCESS WATER FROM COOLING TOWER)

FLUID TEMPERATURE (F)	8.000000E+01	FLUID PRESSURE (PSIA)	9.000000E+01	PIPE LENGTH (M)	1.000000E+03
INTERNAL DIAMETER (IN)	5.087268E+00	PIPE SCHEDULE	1.000000E+01	PIPE COST (\$)	6.824437E+04

INJECTION (PLANT) DESIGN, THERMODYNAMICS, AND COST (NO FLUID DEGRADATION)
(EXCESS WATER FROM COOLING TOWER)

NUMBER OF INJECTION WELLS 1 (WELLS)

ACTUAL WELL FLOW RATE 6.171746E+01 (LBM/SEC)

WELL FIELD DESIGN LATTICE WITH ACTIVE WELLS NUMBERED

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

0 1

0 0

NUMBER OF UPSTREAM WELLS FLOWING INTO EACH NODE

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

1 1

0 0

INITIAL WELL HEAD CONDITIONS

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

ROW	COL 1	COL 2
1	0.	8.000000E+01
2	0.	0.

PRESSURE (PSIA)

ROW	COL 1	COL 2
1	0.	9.000000E+01
2	0.	0.

VISCOSITY (LB/FT-SEC)

ROW	COL 1	COL 2
1	0.	5.762345E-04
2	0.	0.

DENSITY (LB/CU FT)

ROW	COL 1	COL 2
1	0.	6.223749E+01
2	0.	0.

NODAL EXIT CONDITIONS AFTER DEGRADATION AND MIXING

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

ROW	COL 1	COL 2
1	8.000000E+01	8.000000E+01
2	0.	0.

PRESSURE (PSIA)

ROW	COL 1	COL 2
1	9.000000E+01	9.000000E+01
2	0.	0.

VISCOSITY (LB/FT-SEC)

ROW	COL 1	COL 2
1	5.762345E-04	5.762345E-04
2	0.	0.

DENSITY (LB/CU FT)

ROW	COL 1	COL 2
1	6.223749E+01	6.223749E+01
2	0.	0.

INTERNAL PIPE DIAMETER (IN)

ROW	COL 1	COL 2
1	5.087268E+00	5.087268E+00
2	0.	0.

DISPOSAL / INJECTION FLUID CONDITIONS

FLOW RATE 2.221828E+05 (LBM/HR)

TEMPERATURE 8.000000E+01 (F)

PRESSURE 9.000000E+01 (PSIA)

DISPOSAL / INJECTION SYSTEM COSTS (\$)

TOTAL COST 1.139527E+05

FLASH WATER 0.

REINJECTION PUMP

(FIELD LOCATED)

MAINTENANCE COST 5.697637E+03

CAPITAL REPLACEMENT 9.000000E+02 (RATE)

DISPOSAL/INJECTION PIPING ANNUALIZED COST FACTOR

1.365263E-01

PIPE FROM PLANT TO INJECTION FIELD
(EFFLUENT FROM PLANT-LOCATED FLASHER)

FLUID TEMPERATURE (F)	2.676425E+02	FLUID PRESSURE (PSIA)	9.026243E+01	PIPE LENGTH (M)	1.000300E+03
INTERNAL DIAMETER (IN)	1.148956E+01	PIPE SCHEDULE	1.000000E+01	PIPE COST (\$)	1.741641E+05

INJECTION (PLANT) DESIGN, THERMODYNAMICS, AND COST (NO FLUID DEGRADATION)
(EFFLUENT FROM PLANT-LOCATED FLASHER)

NUMBER OF INJECTION WELLS 2 (WELLS)

ACTUAL WELL FLOW RATE 1.353427E+02 (LBH/SEC)

WELLFIELD DESIGN LATTICE WITH ACTIVE WELLS NUMBERED

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

0 1

0 2

NUMBER OF UPSTREAM WELLS FLOWING INTO EACH NODE

PLANT COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

2 1

1 1

INITIAL WELLHEAD CONDITIONS

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

	COL 1	COL 2
ROW 1	0.	2.676425E+02
ROW 2	0.	2.676425E+02

PRESSURE (PSIA)

	COL 1	COL 2
ROW 1	0.	9.026243E+01
ROW 2	0.	9.026243E+01

VISCOSITY (LB/FT-SEC)

	COL 1	COL 2
ROW 1	0.	1.408175E-04
ROW 2	0.	1.408175E-04

DENSITY (LB/CU FT)

	COL 1	COL 2
ROW 1	0.	5.830587E+01
ROW 2	0.	5.830587E+01

NODAL EXIT CONDITIONS AFTER DEGRADATION AND MIXING

TEMPERATURE (F) COL 1 = MANIFOLD NODES, OTHER COLS = WELL NODES

	COL 1	COL 2
ROW 1	2.676425E+02	2.676425E+02
ROW 2	2.676425E+02	2.676425E+02

PRESSURE (PSIA)

	COL 1	COL 2
ROW 1	9.026243E+01	9.026243E+01
ROW 2	9.026243E+01	9.026243E+01

VISCOSITY (LB/FT-SEC)

	COL 1	COL 2
ROW 1	1.408175E-04	1.408175E-04
ROW 2	1.408175E-04	1.408175E-04

DENSITY (LB/CU FT)

	COL 1	COL 2
ROW 1	5.830587E+01	5.830587E+01
ROW 2	5.830587E+01	5.830587E+01

INTERNAL PIPE DIAMETER (IN)

	COL 1	COL 2
ROW 1	1.148956E+01	8.335405E+00
ROW 2	8.335405E+00	8.335405E+00

DISPOSAL / INJECTION FLUID CONDITIONS

FLOW RATE 1.334468E+06 (LBM/HR)

TEMPERATURE 2.676425E+02 (F)

PRESSURE 9.026243E+01 (PSIA)

DISPOSAL / INJECTION SYSTEM COSTS (\$)

TOTAL COST 4.674171E+05

FLASH WATER 0.

REINJECTION PUMP

(FIELD LOCATED)

MAINTENANCE COST 2.337085E+04

CAPITAL REPLACEMENT 9.000000E-02 (RATE)

09/08/75

CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

ECONOMIC ANALYSIS FOR GEOTHERMAL POWER

HIGH TEMPERATURE-LOW SALINITY RESERVOIR

RESERVOIR CHARACTERISTICS

AVERAGE DEPTH	2000.0	M
AVERAGE TEMPERATURE	210.0	C
PRODUCING CAPACITY	275.0	MW(E)

FLUID COMPOSITION

CACO3	0.00	%	
NACL	3.00	%	
SiO2	.04	%	389. PPM
OTHER	0.00	%	
TOTAL DISSOLVED SOLIDS	3.04	%	

WELL DESIGN (AVERAGE)

DEPTH	2000.0	M
BOTTOM DIAMETER	22.225	CM
FRACTION CASED	1.00	

WELL PROPERTIES (AVERAGE)

MW(TH)/WELL	59.7	
MW(E) /WELL (GROSS)	6.9	
MW(E) /WELL (NET)	6.6	
MAXIMUM FLOW RATE/WELL	350000.0	LB/HR
WELL LIFE	10.0	YEARS
PRODUCING WELLS ON LINE	8.0	
DRY WELLS	2.0	
INJECTION WELLS	3.0	
INPUT WELL SPACING	20.0	ACRES
ACTUAL FLOW RATE/WELL	283407.5	#/HR
TOTAL FLOW RATE	2267259.7	#/HR
WELL PRESSURE AT SATURATION	276.7	PSIA
FRACTION STEAM (WELLHEAD)	.30	
STEAM SEPARATION (WELLHEAD)	0	
STEAM/FLASH MIX OPTION	0	
WATER OVERPRESSURIZATION	2.000	
ADJUSTED OVERPRESSURIZATION	1.081	
WATER PRESSURE(PLANT-FLASHING)	299.2	

NONCONDENSIBLE GASES

H2S	.003	%
CO2	.097	%
CH4	0.000	%
OTHER	0.000	%
TOTAL NONCONDENSIBLE GASES	.100	%

STRATIGRAPHY

ROCK TYPE	DEPTH(M)
HARD	2000.0

RESERVOIR ECONOMIC DEVELOPMENT FACTORS

FAVORABLE TARGET FRACTION	.500
FAVORABLE SITE FRACTION	.500
FRACTION OF SITES TO EVALUATE	.667
FRACTION OF SITES TO DRILL	.750
FRACTION OF WELLS TO CASE	.250
FRACTION OF SITES TO DEVELOP	.250

PERCENT NONPRODUCING WELLS	20.0
INJECTION/PRODUCTION WELL FLOW RATE	2.000
FRACTION EXCESS PRODUCING WELLS	.20

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RESERVOIR EXPLORATION COSTS

STEAM SEPARATION AND PLANT FLASH

	TOTAL (DOLLARS)	CAPITALIZED (DOLLARS)	EXPENSED (DOLLARS)	FAVORABLE SITES	BEGINNING MONTH/YEAR	ENDING MONTH/YEAR
IDENTIFICATION OF TARGETS						
LITERATURE SEARCH	2560.	20.0	2540.0	128.	MAY/1970	OCT/1970
PRELIMINARY LAND CHECK	6400.	50.0	6350.0	128.	MAY/1970	OCT/1970
PRELIMINARY RECONNAISSANCE						
LITERATURE SEARCH	8960.	140.0	8820.0	64.	JUN/1970	DEC/1970
GEOLOGICAL RECONNAISSANCE	12800.	200.0	12600.0	64.	JUN/1970	DEC/1970
DETAILED LAND CHECK	15360.	240.0	15120.0	64.	JUN/1970	DEC/1970
DETAILED RECONNAISSANCE						
LEASE COST	384000.	12000.0	372000.0	32.	JUL/1970	MAY/1971
FIELD GEOLOGY	21000.	1000.0	20000.0	21.	SEP/1970	JUN/1971
GEOCHEMICAL EXAMINATION	25200.	1200.0	24000.0	21.	SEP/1970	JUN/1971
GEOPHYSICAL EXAMINATION	105000.	5000.0	100000.0	21.	SEP/1970	JUN/1971
IDENTIFICATION OF DRILLABLE SITES						
HEAT FLOW	38400.	2400.0	36000.0	16.	APR/1971	MAR/1973
TEMPERATURE GRADIENT	40000.	2500.0	37500.0	16.	APR/1971	MAR/1973
ELECTRICAL RESISTIVITY	11200.	700.0	10500.0	16.	APR/1971	MAR/1973
MICROSEISMIC	16000.	1000.0	15000.0	16.	APR/1971	MAR/1973
DETAILED GEOCHEMISTRY	24000.	1500.0	22500.0	16.	APR/1971	MAR/1973
EXPLORATION DRILLING						
COST OF DRILLING	280000.	23333.3	256666.7	4.	APR/1972	MAR/1974
WELL TESTING	8000.	2000.0	6000.0	4.	APR/1974	APR/1974
TOTAL EXPLORATION COST *	998880.	53283.3	945596.7	1.00		
FIELD DEVELOPMENT		TANGIBLE	INTANGIBLE			
PRODUCING WELLS	3200000.	1066666.7	2133333.3		APR/1974	SEP/1977
NONPRODUCING WELLS	600000.	0.0	600000.0		APR/1974	SEP/1977
INJECTION WELLS	1050000.	1050000.0	0.0		OCT/1977	DEC/1979
TRANSMISSION SYSTEM	2478497.	2478496.8	0.0		OCT/1977	DEC/1979
DISPOSAL SYSTEM	467417.	467417.1	0.0		OCT/1977	DEC/1979
TOTAL FIELD DEVELOPMENT COST	7795914.					
FIELD OPERATION						
REPLACEMENT WELL COST	320000.	106666.7	213333.3		JAN/1980	DEC/2008
NONPRODUCING WELL DRILLING COST	64000.	0.0	0.0		JAN/1980	DEC/2008
ABANDONMENT	8000.	0.0	0.0		JAN/1980	DEC/2009
WELL MAINTENANCE	11000.	0.0	0.0		JAN/1980	DEC/2009
OVERHEAD AND MANAGEMENT	136989.	0.0	0.0		JAN/1980	DEC/2009
WELL REDRILLING COST	40000.	0.0	0.0		JAN/1980	DEC/2009
INJECTION COST	0.	0.0	0.0		JAN/1980	DEC/2009
INJECTION WELL COST	0.	0.0	0.0		JAN/1980	DEC/2009
TRANSMISSION SYSTEM MTE.	123925.	0.0	0.0		JAN/1980	DEC/2009
DISPOSAL SYSTEM MTE.	23371.	0.0	0.0		JAN/1980	DEC/2009
TOTAL FIELD OPERATION COST	727284.					

* TOTAL EXPLORATION COST ALLOCATED TO THIS 55. MWE POWER PLANT IS .2000 OF TOTAL EXPLORATION COST FOR THIS 275. MWE RESERVOIR PRODUCING CAPACITY

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

RESERVOIR INPUT DATA

BOND REPAYMENT PROPORTIONAL			
SUM OF YEARS DIGITS DEPRECIATION			
CAPITAL INVESTMENT, \$M	5.1159	(INITIAL FINANCING)	
PROJECT LIFE, YEARS	40.0000		
FRACTION OF INITIAL INVESTMENT IN BONDS	.4200		
BOND INTEREST RATE	.0800		
EQUITY EARNING RATE (AFTER TAXES)	.1500		
FEDERAL INCOME TAX RATE	.4800		
POWER PLANT SIZE (MWE)	55.0000		
DEPRECIABLE LIFE OF WELLS, YRS.	10.0000		
FIRST YEAR OF OPERATION	1980.		
STATE INCOME TAX RATE	.0700		
STATE GROSS REVENUE TAX RATE	0.0000		
PROPERTY TAX RATE	.0250		
DISPOSAL SYSTEM REPLACEMENT RATE	.0900		
TRANSMISSION SYSTEM REPLACEMENT RATE	.6900		
PROPERTY INSURANCE RATE	.0012		
ROYALTY PAYMENT, %	10.00		
PLANT OPERATING LIFE	30.0000		
TRANSMISSION SYSTEM MTE. RATE	.0500		
DISPOSAL SYSTEM MTE. RATE	.0500		
EVALUE	.020000	.015000	
GEOTHERMAL PLANT TYPE	2		
NUMBER OF FLASHING STAGES	1		
LOCATION OF FLASHERS	1		
WELL REINJECTION OPTION	0		
DISTANCE(M) WELLS TO INJECTION FIELD	1000.0000		
PLANT REINJECTION OPTION	1		
DISTANCE(M) PLANT TO INJECTION FIELD	1000.0000		
STEAM SCRUBBER OPTION	1		
CASE GENERATION OPTION	0		
REINJECTION PUMP OPTION	1		
DRILLING COST PER PRODUCING WELL(\$)	400000.		
DRILLING COST PER NONPRODUCING WELL(\$)	300000.		
DRILLING COST PER INJECTION WELL(\$)	350000.		

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

ANNUAL CASH FLOW DATA,

EXPENSES IN \$M/YR

YEAR	LOAD FACTOR	FIELD IDENT.	FIELD EXPLOR.	FIELD DEVELOPMENT	RESERVOIR OPERATION	PROPERTY TAXES AND INSURANCE	INTERIM CAPITAL REPLACEMENT	TOTAL
1 1970	0.00000	.00096	.30705	0.00000	0.00000	.00026	0.00000	.31628
2 1971	0.00000	0.00000	.31387	0.00000	0.00000	.00060	0.00000	.31447
3 1972	0.00000	0.00000	.16580	0.00000	0.00000	.00094	0.00000	.17074
4 1973	0.00000	0.00000	.15620	0.00000	0.00000	.00127	0.00000	.15747
5 1974	0.00000	0.00000	.04300	.81429	0.00000	.00738	0.00000	.86467
6 1975	0.00000	0.00000	0.00000	1.08571	0.00000	.01537	0.00000	1.10108
7 1976	0.00000	0.00000	0.00000	1.38571	0.00000	.02335	0.00000	1.40977
8 1977	0.30000	0.00000	0.00000	1.25828	0.00000	.04098	0.00000	1.29925
9 1978	0.00000	0.00000	0.00000	1.77596	0.00000	.08751	0.00000	1.86347
10 1979	0.00000	0.00000	0.00000	1.77596	0.00000	.13404	0.00000	1.91000
11 1980	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
12 1981	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
13 1982	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
14 1983	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
15 1984	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
16 1985	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
17 1986	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
18 1987	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
19 1988	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
20 1989	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
21 1990	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
22 1991	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
23 1992	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
24 1993	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
25 1994	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
26 1995	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
27 1996	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
28 1997	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
29 1998	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
30 1999	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
31 2000	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
32 2001	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
33 2002	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
34 2003	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
35 2004	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
36 2005	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
37 2006	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
38 2007	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
39 2008	.85000	0.00000	0.00000	0.00000	.72728	.13404	.35963	1.22095
40 2009	.85000	0.00000	0.00000	0.00000	.34329	.13404	0.00000	.47732

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STEAM SEPARATION AND PLANT FLASH

ANNUAL DEDUCTIBLE EXPENSES, \$M

YEAR	10.325 PCT PRESENT WORTH FACTOR	FIELD OPERATING EXPENSES	BOND INTEREST	WELL DEPRECIATION	RESERVOIR DEPLETION AND DEPRECIATION	TOTAL DEDUCTIBLE OPER. EXP.	STATE INCOME TAXES
1 1970	.95206	.00474	0.00000	0.00000	0.00000	.00474	-.00033
2 1971	.86296	.16055	.01054	0.00000	0.00000	.17109	-.01199
3 1972	.78220	.09719	.01941	0.00000	0.00000	.11660	-.00816
4 1973	.70899	.22885	.02547	0.00000	0.00000	.25432	-.01780
5 1974	.64264	1.05043	.02942	0.00000	0.00000	1.07985	-.07559
6 1975	.58250	.79632	.04328	0.00000	0.00000	.83960	-.05877
7 1976	.52799	.80431	.07093	0.00000	0.00000	.87524	-.06127
8 1977	.47857	.62669	.10156	0.00000	0.00000	.72825	-.05098
9 1978	.43379	.08751	.14483	0.00000	0.00000	.23234	-.01626
10 1979	.39319	.13404	.22088	0.00000	0.00000	.35491	-.02484
11 1980	.35639	.75465	.30553	.19394	.25958	1.51370	.11271
12 1981	.32304	.75465	.30638	.26376	.58819	1.91298	.08476
13 1982	.29281	.75465	.30041	.23079	.55871	1.84456	.08955
14 1983	.26540	.75465	.29489	.20170	.53078	1.78283	.09393
15 1984	.24057	.75465	.28980	.17648	.50440	1.72534	.09769
16 1985	.21805	.75465	.28508	.15515	.47957	1.67446	.10146
17 1986	.19765	.75465	.28068	.13770	.45623	1.62931	.10462
18 1987	.17915	.75465	.27652	.12412	.43454	1.58983	.10738
19 1988	.16238	.75465	.27255	.11442	.41434	1.55597	.10975
20 1989	.14719	.75465	.26869	.10861	.39570	1.52764	.11173
21 1990	.13341	.75465	.26485	.10667	.37860	1.50476	.11333
22 1991	.12093	.75465	.26094	.10667	.36304	1.48531	.11470
23 1992	.10961	.75465	.25691	.10667	.34903	1.46726	.11596
24 1993	.09935	.75465	.25270	.10667	.33657	1.45059	.11713
25 1994	.09005	.75465	.24827	.10667	.32566	1.43525	.11820
26 1995	.08163	.75465	.24357	.10667	.31629	1.42119	.11918
27 1996	.07399	.75465	.23855	.10667	.30847	1.40835	.12008
28 1997	.06706	.75465	.23315	.10667	.30220	1.39667	.12090
29 1998	.06079	.75465	.22730	.10667	.29747	1.38699	.12164
30 1999	.05510	.75465	.22093	.10667	.29429	1.37654	.12231
31 2000	.04994	.75465	.21395	.10667	.29266	1.36793	.12291
32 2001	.04527	.75465	.20629	.10667	.29258	1.36018	.12345
33 2002	.04103	.75465	.19783	.10667	.29404	1.35319	.12394
34 2003	.03719	.75465	.18847	.10667	.29704	1.34684	.12439
35 2004	.03371	.75465	.17810	.10667	.30160	1.34102	.12480
36 2005	.03056	.75465	.16657	.10667	.30770	1.33559	.12518
37 2006	.02770	.75465	.15375	.10667	.31535	1.33042	.12554
38 2007	.02510	.75465	.13948	.10667	.32454	1.32534	.12589
39 2008	.02275	.75465	.12357	.10667	.33528	1.32017	.12626
40 2009	.02063	.47732	.10583	.42667	3.82402	4.83383	-.11970

TOTALS=

4.16000

14.47853

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

ANNUAL INCOME STATEMENT, \$M

YEAR	POWER UNITS (M MWH)	TOTAL POWER SALES	BY-PRODUCT SALES	REVENUE TAXES	ROYALTY PAYMENTS EXPENSES	TOTAL TAX DEDUCTIBLE EXPENSES	TAXABLE INCOME (FEDERAL)	FEDERAL INCOME TAX
1 1970	0.00000	0.00000	0.00000	0.00000	0.00000	.00441	-.00441	-.00212
2 1971	0.00000	0.00000	0.00000	0.00000	0.00000	.15912	-.15912	-.07638
3 1972	0.00000	0.00000	0.00000	0.00000	0.00000	.16844	-.16844	-.05205
4 1973	0.00000	0.00000	0.00000	0.00000	0.00000	.23652	-.23652	-.11353
5 1974	0.00000	0.00000	0.00000	0.00000	0.00000	1.00426	-1.00426	-.48205
6 1975	0.00000	0.00000	0.00000	0.00000	0.00000	.78083	-.78083	-.37480
7 1976	0.00000	0.00000	0.00000	0.00000	0.00000	.81397	-.81397	-.39071
8 1977	0.00000	0.00000	0.00000	0.00000	0.00000	.67728	-.67728	-.32509
9 1978	0.00000	0.00000	0.00000	0.00000	0.00000	.21607	-.21607	-.10371
10 1979	0.00000	0.00000	0.00000	0.00000	0.00000	.33007	-.33007	-.15843
11 1980	.40987	3.47091	0.00000	0.00000	.34709	1.62641	1.49741	.71876
12 1981	.40987	3.47091	0.00000	0.00000	.34709	1.99774	1.12608	.54052
13 1982	.40987	3.47091	0.00000	0.00000	.34709	1.93411	1.18971	.57106
14 1983	.40987	3.47091	0.00000	0.00000	.34709	1.87595	1.24787	.59898
15 1984	.40987	3.47091	0.00000	0.00000	.34709	1.82324	1.30058	.62428
16 1985	.40987	3.47091	0.00000	0.00000	.34709	1.77591	1.34791	.64700
17 1986	.40987	3.47091	0.00000	0.00000	.34709	1.73392	1.38990	.66715
18 1987	.40987	3.47091	0.00000	0.00000	.34709	1.69721	1.42661	.68477
19 1988	.40987	3.47091	0.00000	0.00000	.34709	1.66572	1.45810	.69989
20 1989	.40987	3.47091	0.00000	0.00000	.34709	1.63937	1.48445	.71253
21 1990	.40987	3.47091	0.00000	0.00000	.34709	1.61810	1.50572	.72275
22 1991	.40987	3.47091	0.00000	0.00000	.34709	1.60000	1.52382	.73143
23 1992	.40987	3.47091	0.00000	0.00000	.34709	1.58322	1.54060	.73949
24 1993	.40987	3.47091	0.00000	0.00000	.34709	1.56772	1.55610	.74693
25 1994	.40987	3.47091	0.00000	0.00000	.34709	1.55345	1.57037	.75378
26 1995	.40987	3.47091	0.00000	0.00000	.34709	1.54037	1.58345	.76066
27 1996	.40987	3.47091	0.00000	0.00000	.34709	1.52843	1.59539	.76579
28 1997	.40987	3.47091	0.00000	0.00000	.34709	1.51757	1.60625	.77100
29 1998	.40987	3.47091	0.00000	0.00000	.34709	1.50774	1.61608	.77572
30 1999	.40987	3.47091	0.00000	0.00000	.34709	1.49885	1.62497	.77958
31 2000	.40987	3.47091	0.00000	0.00000	.34709	1.49085	1.63297	.78383
32 2001	.40987	3.47091	0.00000	0.00000	.34709	1.48364	1.64118	.78729
33 2002	.40987	3.47091	0.00000	0.00000	.34709	1.47713	1.64669	.79041
34 2003	.40987	3.47091	0.00000	0.00000	.34709	1.47123	1.65259	.79325
35 2004	.40987	3.47091	0.00000	0.00000	.34709	1.46581	1.65801	.79584
36 2005	.40987	3.47091	0.00000	0.00000	.34709	1.46077	1.66305	.79826
37 2006	.40987	3.47091	0.00000	0.00000	.34709	1.45596	1.66786	.80057
38 2007	.40987	3.47091	0.00000	0.00000	.34709	1.45123	1.67259	.80284
39 2008	.40987	3.47091	0.00000	0.00000	.34709	1.44643	1.67739	.80515
40 2009	.40987	3.47091	0.00000	0.00000	.34709	4.71413	-1.59031	-.76335

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STEAM SEPARATION AND PLANT FLASH

PAYOUT OF INVESTMENTS, \$M

YEAR	NET CASH FLOW	OUTSTANDING BONDS	EQUITY CAPITAL NOT RECOVERED	BOND INTEREST	EARNINGS ON UNRECOVERED EQUITY	BONDS REPAID	RECOVERY OF EQUITY
1 1970	-.31383	0.00000	0.00000	0.00000	0.00000	-.13181	-.18202
2 1971	-.26396	.13181	.18202	.01054	.02730	-.11086	-.15310
3 1972	-.18020	.24267	.33512	.01941	.35027	-.07569	-.10452
4 1973	-.11755	.31836	.43964	.02547	.06595	-.04937	-.06818
5 1974	-.41263	.36773	.50782	.02942	.07617	-.17330	-.23932
6 1975	-.82287	.54103	.74714	.04328	.11207	-.34560	-.47726
7 1976	-.91169	.88663	1.22440	.07093	.18366	-.38291	-.52878
8 1977	-1.28772	1.26954	1.75318	.10156	.26298	-.54084	-.74688
9 1978	-2.26333	1.81039	2.50006	.14483	.37501	-.95060	-1.31273
10 1979	-2.51952	2.76098	3.81279	.22088	.57192	-1.05820	-1.46132
11 1980	-.02525	3.81918	5.27411	.33553	.79112	-.01060	-.01464
12 1981	.17790	3.82978	5.28875	.30638	.79331	.07472	.10318
13 1982	.16402	3.75507	5.18557	.30041	.77784	.06889	.09513
14 1983	.15151	3.68618	5.09044	.29489	.76357	.06363	.08787
15 1984	.14051	3.62255	5.00257	.28980	.75639	.05901	.08149
16 1985	.13117	3.56354	4.92108	.28508	.73816	.05509	.07608
17 1986	.12368	3.50845	4.84500	.28068	.72675	.05194	.07173
18 1987	.11821	3.45650	4.77327	.27652	.71599	.04965	.06856
19 1988	.11498	3.40686	4.70471	.27255	.70571	.04829	.06669
20 1989	.11421	3.35857	4.63802	.26869	.69570	.04797	.06624
21 1990	.11617	3.31060	4.57178	.26485	.68577	.04879	.06738
22 1991	.12013	3.26180	4.50440	.26094	.67566	.05046	.06968
23 1992	.12531	3.21135	4.43472	.25691	.66521	.05263	.07268
24 1993	.13181	3.15872	4.36204	.25270	.65431	.05536	.07645
25 1994	.13978	3.10336	4.28559	.24827	.64284	.05871	.08107
26 1995	.14938	3.04465	4.20452	.24357	.63068	.06274	.08664
27 1996	.16076	2.98191	4.11788	.23855	.61768	.06752	.09324
28 1997	.17412	2.91439	4.02464	.23315	.60370	.07313	.10099
29 1998	.18966	2.84126	3.92365	.22730	.58855	.07966	.11000
30 1999	.20760	2.76161	3.81365	.22093	.57265	.08719	.12041
31 2000	.22819	2.67441	3.69324	.21395	.55399	.09584	.13235
32 2001	.25171	2.57857	3.56089	.20629	.53413	.10572	.14599
33 2002	.27845	2.47286	3.41490	.19783	.51223	.11695	.16150
34 2003	.30875	2.35591	3.25340	.18847	.48801	.12968	.17908
35 2004	.34298	2.22623	3.07432	.17810	.46115	.14405	.19893
36 2005	.38154	2.08218	2.87539	.16657	.43131	.16025	.22130
37 2006	.42489	1.92193	2.65410	.15375	.39811	.17845	.24643
38 2007	.47351	1.74348	2.40766	.13948	.36115	.19887	.27463
39 2008	.52794	1.54451	2.13303	.12357	.31995	.22174	.30621
40 2009	3.14970	1.32287	1.82662	.10583	.27402	1.32287	1.82682

09/88/75

CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

	DETAILED CASH FLOW		DISTRIBUTION OF ENERGY COSTS	
	MILLS PER KWHE	ANNUAL (\$ MILLIONS)	MILLS PER KWHE	ANNUAL (\$ MILLIONS)
C O S T O F P O W E R	8.46839	3.47091		
FIELD IDENTIFICATION AND EXPLORATION	.56593	.23360	.76456	.31337

FIELD DEVELOPMENT (TOTAL)	2.56924	1.05305	3.90037	1.59863

PRODUCING WELLS	1.20634	.49444	1.58402	.64924
TRANSMISSION SYSTEM	.70505	.28898	1.28085	.52498
DISPOSAL SYSTEM	.43166	.17692	.78418	.32141
NONPRODUCING WELLS	.22619	.09271	.25132	.10301
FIELD OPERATING COSTS (TOTAL)	3.06231	1.25514	3.80346	1.55891

DISPOSAL COSTS	.38832	.15916	.55305	.22668
PRODUCING WELLS	.92023	.37717	1.10320	.45216
TRANSMISSION COSTS	.84348	.34571	1.13579	.46552
OTHER OPERATING COSTS	.91029	.37310	1.01143	.41455
REVENUE TAXES	0.00000	0.00000		
STATE INCOME TAXES	.13108	.05372		
ROYALTY PAYMENTS	.84684	.34709		
FEDERAL INCOME TAXES	.83590	.34261		
BOND INTEREST	.45309	.18571		
BY PRODUCT REVENUE	0.00000	0.00000	0.00000	0.00000
TOTALS	8.46839	3.47091	8.46839	3.47091

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

POWER PLANT CAPITAL COSTS

ACCOUNT

1.0	POWER PLANT		
1.1	PIPING, INSULATION, & PUMPS	366.	\$K
1.2	CRANE	189.	\$K
1.3	TURBO GENERATOR	4554.	\$K
1.6	FLASHERS (PLANT LOCATED UNITS)	194.	\$K
1.9	MISC. PROCESS SUPPORT EQUIPMENT	133.	\$K
1.10	INSTRUMENTATION AND CONTROLLERS	560.	\$K
1.12	ELECTRICAL SUPPORT AND EQUIPMENT	722.	\$K
1.16	CONDENSER	939.	\$K
1.17	INSTALLATION TESTING	170.	\$K
1.18	BUILDINGS, FOUNDATIONS, AND SUPPORT EQUIPMENT	1570.	\$K
1.19	GAS EJECTORS (STEAM DRIVEN)	131.	\$K
1.20	FLASH WATER REINJECTION PUMP (PLANT LOCATED FLASHER UNIT)	68.	\$K
1.21	COOLING TOWER REINJECTION PUMP	24.	\$K
1.99	SUBTOTAL 1.0	9620.	\$K

ACCOUNT

2.0	HEAT REJECTION SYSTEM (COOLING TOWERS)		
2.1	COOLING TOWER SYSTEM (FORCED DRAFT NET)	1259.	\$K
2.99	SUBTOTAL 2.0	1259.	\$K

ACCOUNT

3.0	SWITCH YARD		
3.99	SUBTOTAL 3.0	777.	\$K

ACCOUNT

5.0	OTHER COSTS		
5.1	ENGINEERING AND DESIGN	1166.	\$K
5.2	ADMINISTRATION AND INDIRECT COSTS	932.	\$K
5.99	SUBTOTAL 5.0	2098.	\$K

TOTAL POWER PLANT COST	13754.	\$K
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CASH FLOW AND POWER COSTS
STEAM SEPARATION AND PLANT FLASH

POWER PLANT INPUT DATA

BOND REPAYMENT PROPORTIONAL		
SUM OF YEARS DIGITS DEPRECIATION		
PLANT INVESTMENT, \$M	13.7540	(INITIAL FINANCING)
PROJECT LIFE, YEARS	33.0000	
FRACTION OF INITIAL INVESTMENT IN BONDS	.5900	
BOND INTEREST RATE	.0800	
EQUITY EARNING RATE (AFTER TAXES)	.1200	
FEDERAL INCOME TAX RATE	.4800	
POWER PLANT SIZE (MWE)	55.0000	
DEPRECIABLE LIFE OF PLANT, YRS.	30.0000	
PLANT CONSTRUCTION AND LICENSING, YRS.	3.0000	
FIRST YEAR OF OPERATION	1980	
STATE INCOME TAX RATE	.0700	
STATE GROSS REVENUE TAX RATE	.0400	
PROPERTY TAX RATE	.0250	
INTERIM CAPITAL REPLACEMENTS, RATE/YR	.0035	
PROPERTY INSURANCE RATE	.0012	
ROYALTY PAYMENT, %	0.0000	
PLANT OPERATING LIFE	30.0000	

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

CASH FLOW TABLE POWER PLANT, \$ MILLIONS

YEAR	LOAD FACTOR	CAPITAL COSTS	ENERGY COSTS	PLANT OPERATING COSTS	INTERIM CAPITAL REPLACEMENT	PROPERTY TAXES INSURANCE	TOTAL COSTS
1 1977	0.00000	1.30119	0.00000	0.00000	0.00000	0.00000	1.30119
2 1978	0.00000	7.46742	0.00000	0.00000	0.00000	.03409	7.50151
3 1979	0.00000	4.98539	0.00000	0.00000	0.00000	.22974	5.21513
4 1980	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
5 1981	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
6 1982	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
7 1983	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
8 1984	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
9 1985	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
10 1986	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
11 1987	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
12 1988	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
13 1989	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
14 1990	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
15 1991	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
16 1992	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
17 1993	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
18 1994	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
19 1995	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
20 1996	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
21 1997	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
22 1998	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
23 1999	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
24 2000	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
25 2001	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
26 2002	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
27 2003	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
28 2004	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
29 2005	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
30 2006	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
31 2007	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
32 2008	.85000	0.00000	3.47091	.10862	.04814	.36035	3.98802
33 2009	.85000	0.00000	3.47091	.10862	0.00000	.36035	3.93988

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

ANNUAL TAX DEDUCTIBLE EXPENSES, \$ MILLIONS

YEAR	7.203 PCT PRESENT WORTH FACTOR	OPERATING EXPENSES	BOND INTEREST	DEPRECIATION	TOTAL DEDUCTIBLE OPERATING EXPENSES	STATE INCOME TAX
1 1977	.96582	0.00000	0.00000	0.00000	0.00000	0.00000
2 1978	.90093	.03409	.06142	0.00000	.09551	-.00669
3 1979	.84040	.22974	.41968	0.00000	.64882	-.04542
4 1980	.78394	3.93988	.68982	.88735	5.51706	.02279
5 1981	.73127	3.93988	.67671	.90291	5.51951	.02262
6 1982	.68214	3.93988	.66229	.87054	5.47271	.02590
7 1983	.63631	3.93988	.64761	.83837	5.42587	.02918
8 1984	.59355	3.93988	.63266	.80641	5.37896	.03246
9 1985	.55368	3.93988	.61741	.77466	5.33196	.03575
10 1986	.51648	3.93988	.60184	.74312	5.28484	.03905
11 1987	.48178	3.93988	.58591	.71178	5.23758	.04236
12 1988	.44941	3.93988	.56961	.68065	5.19014	.04568
13 1989	.41921	3.93988	.55288	.64972	5.14249	.04901
14 1990	.39105	3.93988	.53571	.61900	5.09460	.05236
15 1991	.36477	3.93988	.51804	.58849	5.04642	.05574
16 1992	.34027	3.93988	.49985	.55819	4.99793	.05913
17 1993	.31740	3.93988	.48169	.52809	4.94907	.06255
18 1994	.29608	3.93988	.46171	.49821	4.89980	.06600
19 1995	.27619	3.93988	.44166	.46852	4.85006	.06948
20 1996	.25763	3.93988	.42089	.43905	4.79982	.07300
21 1997	.24032	3.93988	.39934	.40978	4.74900	.07656
22 1998	.22417	3.93988	.37695	.38072	4.69756	.08016
23 1999	.20911	3.93988	.35366	.35187	4.64541	.08381
24 2000	.19506	3.93988	.32940	.32322	4.59259	.08751
25 2001	.18196	3.93988	.30409	.29478	4.53875	.09127
26 2002	.16973	3.93988	.27764	.26655	4.48407	.09510
27 2003	.15833	3.93988	.24998	.23852	4.42839	.09900
28 2004	.14769	3.93988	.22101	.21070	4.37160	.10297
29 2005	.13777	3.93988	.19064	.18309	4.31361	.10703
30 2006	.12851	3.93988	.15874	.15569	4.25432	.11118
31 2007	.11988	3.93988	.12522	.12849	4.19360	.11543
32 2008	.11182	3.93988	.08995	.10150	4.13133	.11979
33 2009	.10431	3.93988	.05279	.05006	4.06914	.12424

DEPRECIATION SUM = 15.1500

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CASH FLOW AND POWER COSTS
STEAM SEPARATION AND PLANT FLASH

ANNUAL INCOME STATEMENT, \$ MILLIONS

YEAR	POWER UNITS (M MWH)	TOTAL POWER SALES	REVENUE TAXES	TOTAL TAX DEDUCTIBLE EXPENSES	TAXABLE INCOME (FEDERAL)	FEDERAL INCOME TAX
1 1977	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
2 1978	0.00000	0.00000	0.00000	.08882	-.08882	-.04263
3 1979	0.00000	0.00000	0.00000	.60340	-.60340	-.28963
4 1980	.39401	6.08611	.24344	5.53985	.30281	.14535
5 1981	.39401	6.08611	.24344	5.54213	.30053	.14426
6 1982	.39401	6.08611	.24344	5.49861	.34406	.16515
7 1983	.39401	6.08611	.24344	5.45504	.38762	.18606
8 1984	.39401	6.08611	.24344	5.41142	.43125	.20700
9 1985	.39401	6.08611	.24344	5.36771	.47496	.22798
10 1986	.39401	6.08611	.24344	5.32389	.51878	.24901
11 1987	.39401	6.08611	.24344	5.27993	.56273	.27011
12 1988	.39401	6.08611	.24344	5.23581	.60685	.29129
13 1989	.39401	6.08611	.24344	5.19150	.65117	.31256
14 1990	.39401	6.08611	.24344	5.14696	.69571	.33394
15 1991	.39401	6.08611	.24344	5.10216	.74051	.35544
16 1992	.39401	6.08611	.24344	5.05706	.78561	.37709
17 1993	.39401	6.08611	.24344	5.01162	.83105	.39890
18 1994	.39401	6.08611	.24344	4.96580	.87687	.42090
19 1995	.39401	6.08611	.24344	4.91955	.92312	.44310
20 1996	.39401	6.08611	.24344	4.87282	.96985	.46553
21 1997	.39401	6.08611	.24344	4.82556	1.01710	.48821
22 1998	.39401	6.08611	.24344	4.77772	1.06495	.51118
23 1999	.39401	6.08611	.24344	4.72922	1.11344	.53445
24 2000	.39401	6.08611	.24344	4.68001	1.16265	.55807
25 2001	.39401	6.08611	.24344	4.63002	1.21264	.58217
26 2002	.39401	6.08611	.24344	4.57918	1.26349	.60647
27 2003	.39401	6.08611	.24344	4.52739	1.31528	.63133
28 2004	.39401	6.08611	.24344	4.47458	1.36809	.65668
29 2005	.39401	6.08611	.24344	4.42065	1.42202	.68257
30 2006	.39401	6.08611	.24344	4.36550	1.47717	.70994
31 2007	.39401	6.08611	.24344	4.30903	1.53363	.73614
32 2008	.39401	6.08611	.24344	4.25113	1.59154	.76394
33 2009	.39401	6.08611	.24344	4.19243	1.64823	.78775

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CASH FLOW AND POWER COSTS

STEAM SEPARATION AND PLANT FLASH

PAYOUT OF INVESTMENTS, \$ MILLIONS

YEAR	NET CASH FLOW	OUTSTANDING BONDS	EQUITY CAPITAL NOT RECOVERED	BOND INTEREST	EARNINGS ON UNRECOVERED EQUITY	BONDS REPAID	RECOVERY OF EQUITY
1 1977	-1.30119	0.00000	0.00000	0.00000	0.00000	-.76770	-.53349
2 1978	-7.57763	.76770	.53349	.06142	.06402	-4.47080	-3.10683
3 1979	-5.73600	5.23850	3.64031	.41908	.43684	-3.38424	-2.35176
4 1980	.27763	8.62274	5.99207	.68982	.71905	.16380	.11383
5 1981	.30566	8.45894	5.87824	.67671	.70539	.18034	.12532
6 1982	.31096	8.27860	5.75292	.66229	.69035	.18347	.12749
7 1983	.31675	8.09513	5.62543	.64761	.67505	.18688	.12987
8 1984	.32306	7.90825	5.49556	.63266	.65947	.19060	.13245
9 1985	.32993	7.71765	5.36311	.61741	.64357	.19466	.13527
10 1986	.33740	7.52299	5.22784	.60184	.62734	.19907	.13833
11 1987	.34552	7.32393	5.08951	.58591	.61074	.20386	.14166
12 1988	.35433	7.12007	4.94785	.56961	.59374	.20905	.14527
13 1989	.36388	6.91102	4.80257	.55288	.57631	.21469	.14919
14 1990	.37423	6.69633	4.65338	.53571	.55841	.22079	.15343
15 1991	.38542	6.47553	4.49995	.51804	.53999	.22740	.15802
16 1992	.39754	6.24813	4.34192	.49985	.52103	.23455	.16299
17 1993	.41063	6.01359	4.17893	.48109	.50147	.24227	.16836
18 1994	.42477	5.77132	4.01058	.46171	.48127	.25061	.17416
19 1995	.44004	5.52070	3.83642	.44166	.46037	.25962	.18041
20 1996	.45651	5.26108	3.65601	.42089	.43872	.26934	.18717
21 1997	.47428	4.99174	3.46884	.39934	.41626	.27982	.19445
22 1998	.49343	4.71192	3.27438	.37695	.39293	.29112	.20231
23 1999	.51407	4.42080	3.07208	.35366	.36865	.30330	.21077
24 2000	.53630	4.11750	2.86131	.32940	.34336	.31642	.21988
25 2001	.56024	3.80108	2.64143	.30499	.31697	.33054	.22973
26 2002	.58601	3.47054	2.41173	.27764	.28941	.34575	.24027
27 2003	.61375	3.12479	2.17146	.24998	.26058	.36211	.25164
28 2004	.64359	2.76268	1.91983	.22101	.23038	.37972	.26387
29 2005	.67569	2.38296	1.65595	.19064	.19871	.39866	.27703
30 2006	.71020	1.98430	1.37892	.15874	.16547	.41902	.29118
31 2007	.74731	1.56528	1.08774	.12522	.13053	.44031	.30640
32 2008	.78720	1.12437	.78134	.08995	.09376	.46445	.32275
33 2009	1.11851	.65992	.45859	.05279	.05503	.45992	.45859

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CASH FLOW AND POWER COSTS

I N S T A L L E D C O S T

STEAM SEPARATION AND PLANT FLASH
250.07273 \$ PER KWE

	DETAILED CASH FLOW MILLS PER KWHR	ANNUAL (\$ MILLIONS)	EQUIVALENT CASH FLOW MILLS PER KWHR	ANNUAL (\$ MILLIONS)
C O S T O F P O W E R	15.44666	6.08611	15.44666	6.08611
C O S T D I S T R I B U T I O N				
INITIAL PLANT	3.02335	1.19122	4.81152	1.89578
INTERIM CAPITAL REPLACEMENTS	.12093	.04765	.16110	.06347
ENERGY SUPPLY	8.80924	3.47091	9.17629	3.61533
OPERATING EXPENSES	.27568	.10362	.28716	.11314
PROPERTY TAXES AND INSURANCE	.97016	.38225	1.01059	.39818
STATE REVENUE TAX	.61787	.24344		
STATE INCOME TAX	.12067	.04755		
FEDERAL INCOME TAX	.76954	.30320		
BOND INTEREST	.73923	.29126		
TOTAL	15.44666	6.08611	15.44666	6.08611
INTERNAL POWER CONSUMPTION 2.1 MWE	.59766	.23548		

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